BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2019-185-E
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In the Matter of: South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)	))))))))))))))	**REBUTTAL TESTIMONY OF GLEN A. SNIDER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Duke Energy as Director of Carolinas Integrated Resource Planning and Analytics.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I did.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony is to address the policy and technical arguments raised by the Office of Regulatory Staff ("ORS"), South Carolina Solar Business Association ("SBA"), and Southern Alliance for Clean Energy/South Carolina Coastal Conservation League ("SACE/CCL") regarding Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP") (together, the "Companies" or "Duke") avoided energy and capacity rates applicable to qualifying facilities ("QFs") under the Public Utilities Regulatory Policy Act of 1978 ("PURPA"), as well as ancillary services costs. Specifically, my Rebuttal Testimony responds to the Direct Testimony of ORS Witness Brian Horii and Robert Lawyer, SBA Witnesses Hamilton Davis and Ed Burgess, and SACE/CCL Witness James Wilson.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. My Rebuttal Testimony is organized as follows:

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. My Rebuttal Testimony:

1) Dismisses SBA Witness Davis' and Witness Burgess' unsubstantiated policy arguments that Duke is biased against QFs and incentivized to keep avoided cost rates as low as possible by explaining that: (i) QF solar has little impact on the need for future generation resources due to its intermittent, non-dispatchable nature, and therefore little to displace utility-owned generation; (ii) Duke is financially indifferent to purchasing any type of fuel resource due to Duke's ability to recover its purchased power costs paid to QFs through the annual fuel clause; and (iii) it is a fact that solar development community is the party in this case that will financially benefit from artificially higher, inaccurate avoided cost rates;

2) Explains that SBA Witness Davis' and Witness Burgess' arguments that Duke is thwarting "competition" from solar QFs cannot be reconciled with the fact that DEC and DEP are currently undertaking significant system-wide competitive solicitations for new renewable QF resource capacity at purchase rates below avoided costs. Duke is enabling real competition between QF developers for the benefit of the consumer;

3) Dismisses SBA Witness Davis' "zone of reasonableness" argument by explaining that the concept is inapplicable in setting avoided cost rates under PURPA, since PURPA prohibits unjustly subsidizing QFs by paying rates that exceed the utility's actual avoided costs;

4) Explains that the Companies have accurately calculated their avoided energy cost rates, as agreed upon by the ORS, and, in doing so, have accurately modeled for "real world" system operations; accurately modeled marginal avoidable resources for DEP as a single regulated utility and Balancing Authority; appropriately excluded a fuel hedge from avoided energy rates, as avoided energy rates are limited to real costs actually being avoided; and appropriately included environmental costs in calculating DEC's and DEP's avoided energy rates;

5) Explains that it is appropriate to apply a more accurate solar generation profile for large QFs ineligible for the standard offer in calculating such QFs' energy rates. Both FERC's regulations implementing PURPA and Act 62 expressly reference a QF's specific characteristics to be taken into account and the Commission has previously approved use of a solar generation profile to calculate avoided energy costs for Dominion Energy South Carolina, contrary to SBA Witness Burgess' assertions;

6) Dismisses SBA Witness Burgess' arguments against the Companies' energy rate design, explaining that the design provides sufficient seasonal and hourly granularity and appropriate price signals that incentivize QFs to maximize output during times when energy has the most value to the Companies and customers;

7) Supports the Companies' avoided capacity rate calculation as reasonable and appropriate, and explains that acceptance of ORS Witness Horii's recommendation to use a 20-year useful life of a CT when calculating avoided capacity costs would be unprecedented in South Carolina and does not align with the significantly longer 40-year useful lives approved for fixing rates in the Companies' DSM/EE, and base rate case proceedings;

8) Dismisses SBA Witness Burgess' recommended upward adjustments to the avoided capacity cost as erroneous and unreasonable, explaining that the Companies used the appropriate CT technology consistent with industry standards, appropriately adjusted for economies of scale to accurately calculate the capital cost for a new peaker, and determined the Companies' first year of need and corresponding assumed capacity value based upon DEC's and DEP's most recent integrated resource plans ("IRPs");

9) Supports the Companies' updated, more granular seasonal allocation, and rebuts SBA Witness Burgess' and SACE/CCL's Witness Wilson's

arguments concerning the Companies' underlying Solar Capacity Value study supporting the seasonal allocation; and,

10) Provides support for the Solar Integration Services Charge ("SISC"), which is supported by ORS Witness Horii as well as the North Carolina Public Staff ("NC Public Staff"), as further discussed by Duke Witness Wintermantel. No parties dispute that the Companies are incurring additional costs to integrate solar, and the Companies intentionally balanced both the QFs' and customers' interests in implementing and establishing the SISC. The Companies have also provided QFs an option to avoid the SISC through operating their facilities as "controlled solar generators."

II. <u>GENERAL OBSERVATIONS AND CONSIDERATIONS</u>

Q. WHAT ARE YOUR GENERAL OBSERVATIONS OF INTERVENOR TESTIMONY IN THIS PROCEEDING?

A. ORS's Direct Testimony presents two areas of disagreement with Duke's calculation of avoided capacity costs, but, overall, presents a fair and reasonable view of the objectives of this proceeding, in terms of fully and accurately calculating DEC's and DEP's avoided costs under PURPA and Act 62. SACE/CCL's Witnesses have similarly presented technical arguments regarding the Companies' quantification of DEC's and DEP's avoided capacity, avoided energy and the Integration Services Charge that I disagree with and will address later in my Rebuttal Testimony. However, SBA's and JDA's Witnesses raise a number of rhetorical and policy arguments[1] to paint a picture that Duke has shown "anti-QF" bias in this proceeding. Specifically, the Witnesses on behalf of the solar industry suggest that Duke has purposefully designed artificially low avoided cost rates in an effort to obstruct solar QF development so that Duke can build more utility-owned generation, thereby avoiding "competition" by QFs. Before turning

[1] *See generally* SBA Davis Direct, at 7-19; SBA Burgess Direct, at 7-20; JDA Chilton Direct, at 6-7.

to the more technical issues raised by ORS and other intervenors, I address these allegations and ask the Commission to reject the solar industry's unsubstantiated arguments to adopt higher avoided cost rates above the value of QF energy and capacity actually being delivered to customers.

Q. SBA WITNESS DAVIS INITIALLY SUGGESTS THAT DUKE IS INCENTIVIZED TO KEEP AVOIDED COST RATES AS LOW AS POSSIBLE IN ORDER TO "RENDER QFs ECONOMICALLY INFEASIBLE, REDUCING DIRECT COMPETITION WITH THE UTILITY."[2] IS THIS TRUE?

A. No. SBA Witness Davis is mistaken in his assertion that Duke is incentivized to keep avoided cost rates as low as possible or that the Companies' calculation of avoided cost in this proceeding is somehow designed to render QFs economically infeasible or to reduce competition. First, the deployment of QF solar onto the power system does little to offset the need for future generation because it does not provide a net dependable resource capable of meeting DEC's and DEP's future capacity requirements, which occur in predominately non-daylight hours. As a result, adding non-dispatchable QF solar has little impact on the need for future generation but rather serves as a non-firm intermittent resource that reduces fuel purchases. Second, the cost of QF power is a pass-through expense paid directly by Duke's customers in the same way natural gas or coal fuel costs are a pass through. Therefore, Duke is financially indifferent to purchasing any of these fuel sources and has no natural incentive to lower avoided cost rates. Rather, the

[2] SBA Davis Direct, at 18-19.

Company is obligated to produce an accurate avoided cost rate that reflects DEC's and DEP's future energy pricing and capacity needs. An accurate avoided cost rate, such as that proposed by DEC and DEP, protects SC residents and businesses (not the utilities) from bearing unnecessary costs that could otherwise occur if these administratively-determined prices are set artificially higher than the value created for consumers. Accordingly, Duke has no incentive to keep avoided cost rates "as low as possible," as alleged by Mr. Davis.

Q. SBA WITNESS BURGESS MAKES A SIMILAR ARGUMENT THAT "IT IS LOGICAL FOR DUKE TO PURSUE SOLE OWNERSHIP OF GENERATION ASSETS, RATHER THAN ENABLE COMPETITIVE GENERATORS SUCH AS QFS TO CROWD OUT POTENTIAL UTILITY OWNED ASSETS"[3]? IS THIS TRUE?

A. Again, no. Similar to the allegations by Witness Davis, Mr. Burgess attempts to construct an argument that Duke is biased against QFs and has intentionally designed its avoided cost rates to stifle QF development in an effort to pursue sole ownership of generation assets in the Carolinas.

The Commission should disregard these unsubstantiated arguments, both because they are false and because they cannot objectively be reconciled with reality. First, as I explain above, non-dispatchable QF solar generation provides very little incremental capacity value to the system during the periods when DEC and DEP project future loss of load risk that drives capacity additions. As a result, solar QFs are not actually competing to serve DEC's and DEP's future capacity

[3] SBA Burgess Direct, at 8-9.

needs. Moreover, as described in Duke Witness Brown's Rebuttal Testimony, PURPA guarantees that utilities must purchase QF output under administratively-established avoided cost rates, and this "guarantee" eliminates any notion of competition. Second, Mr. Burgess fails to even recognize that Duke is currently undertaking significant system-wide competitive solicitations of new renewable energy resources under the Competitive Procurement of Renewable Energy ("CPRE") Program. As described by Duke Witness George Brown, the CPRE Program is designed to procure the most cost-effective utility-scale renewable energy resources across the DEC and DEP systems (whether located in North Carolina or South Carolina and whether delivered by the utility or a third party independent power producer) at prices below the Companies' avoided costs. The fact that the Companies have competitively procured approximately 600 megawatts of solar generation in 2019 and are planning to competitively procure significant additional megawatts of QF solar over the next few years simply cannot be reconciled with Mr. Burgess' arguments that Duke is attempting to use its avoided cost rates to stifle competition.

Q. MR. BURGESS NEXT ALLEGES THAT DUKE IS BIASED AGAINST SOLAR QFS AND HAS "AN INCENTIVE TO PROPOSE ARTIFICIALLY LOW AVOIDED COST RATES."[4] WHAT EVIDENCE CAN YOU PROVIDE THE COMMISSION THAT DUKE HAS NOT APPLIED AN ANTI-QF BIAS IN DEVELOPING AVOIDED COST RATES PRESENTED FOR COMMISSION APPROVAL IN THIS PROCEEDING?

A. In considering this argument, I would ask the Commission to take a step back and consider how Duke's avoided costs have been derived. Mr. Burgess alleges that "Duke has made many small but meaningful methodological choices that each drive rates down incrementally," and "in the aggregate, [are] significantly biased against solar QFs."[5] Put another way, Mr. Burgess argues that Duke has intentionally made adjustments or "choices" in its avoided cost methodology to disadvantage solar QFs by causing the avoided cost rates to be lower than Duke's most accurate forecasts of DEC's and DEP's future capacity needs and projections of future system marginal costs. Once again, Mr. Burgess' rhetorical arguments have no basis in reality, as Duke consistently uses the same system production cost models, data inputs, forward looking projections and planning assumptions to calculate avoided cost paid to QFs that are used to identify the utility's future energy costs and timing of planned generating resources shown in its integrated resource planning processes. More specifically, the Companies' avoided energy and capacity costs are calculated using largely the same data inputs and assumptions presented in

[4] SBA Burgess Direct, at 9.
[5] SBA Burgess Direct, at 10.

DEC's and DEP's 2019 IRPs, as recently filed with the Commission on September 4, 2019. This is a practice that has been utilized in Duke's resource planning and development of avoided costs for many years. If, as I believe to be the case, the Companies' IRPs represent the most accurate estimates of Duke's energy costs and capacity needs, I question what "methodological choices" Mr. Burgess alleges that Duke purposefully made to disadvantage solar QFs. As explained in my direct testimony, Duke has generally relied upon the most current IRP assumptions and consistently applied the same peaker methodology as in past avoided cost filings. Moreover, as I explain in more detail later in my Rebuttal Testimony, the few small adjustments made in this case relative to the 2019 IRPs actually increased the Companies' avoided cost rate, not decreased it, as claimed by Witness Burgess. For example, in the development of capacity rates in this case the Companies relied upon public Energy Information Association ("EIA") Combustion Turbine ("CT") cost data rather than lower cost proprietary engineering estimates of CT costs as used in the 2019 IRP. The EIA CT cost data yielded higher avoided capacity costs relative to the Duke's internal CT costs assumptions. Furthermore, the Companies' IRPs assume more solar will be installed over the 10 year avoided cost rate period than the installed and obligated solar recognized in calculating the avoided cost rates. Since each increment of solar generation reduces the value of the next increment, the Companies' avoided cost rates would have been lower if the Companies had fully accounted for the future solar projected in their IRPs to be installed over the next 10 years. Again, Duke's adjustments to the most recent 2019

IRP data served to increase, not decrease, avoided costs relative to IRP assumptions.

In sum, Duke has consistently and appropriately relied upon its most current resource planning assumptions and the well-established peaker methodology, and, in no way, has applied novel methodological choices to craft artificially low rates avoided cost rates in this proceeding. Mr. Burgess fails to provide any credible arguments to suggest that the Companies applied any sort bias in developing avoided cost rates, and his arguments in this regard should be rejected

Q. MR. BURGESS ALSO PUTS FORWARD A CONCEPT CALLED THE "ZONE OF REASONABLENESS" IN AN EFFORT TO PROMOTE THE COMMISSION ADOPTING HIGHER AVOIDED COST RATES IN THIS PROCEEDING? ARE YOU FAMILIAR WITH THIS CONCEPT?

A. No, not in the context of setting avoided cost rates. While I am generally aware that a "zone of reasonableness" concept has been recognized in state ratemaking proceedings when looking at rate parity between customer classes, this concept is wholly inapplicable to quantification of avoided cost rates under PURPA. As explained by Duke Witness Brown, PURPA prohibits unjustly subsidizing QFs by paying rates that exceed avoided costs. Congress was explicit that the rates to be paid to QFs should not exceed the utility's "incremental cost of alternative energy" which is "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[6] Act 62 relies upon precisely the same definition as Congress to define avoided costs.[7]

Q. PLEASE COMMENT ON THE SPECIFIC RISKS THAT MR. BURGESS IDENTIFIES TO SUPPORT HIS "ZONE OF REASONABLENESS" ARGUMENT.

A. Mr. Burgess' testifies that the Commission should adopt higher avoided cost rates under his zone of reasonableness theory based upon certain risks that he perceives with utility-owned generation. He suggests that the "clearest risk of QF rates approved below a utility's avoided costs is stifled competition in the market" which he suggests "can be detrimental to the diversity of the utility's resource mix." He further suggests that "[a] less commonly understood but equally significant risk of low QF rates is the loss of a hedge against cost overruns associated with large traditional resource procurements."[8]

In my opinion, these purported "risks" are neither accurately characterized nor relevant whatsoever to the Commission's evaluation of the Companies' avoided costs calculated pursuant to PURPA. First, as Witness Brown explains, the fixing of administratively determined avoided cost rates based upon Duke's future cost of energy and capacity does not enable "competition" as asserted by Mr. Burgess and SBA's other witnesses. Thus, Mr. Burgess' assertion is false that competition will be "stifled" if avoided cost rates are not set high enough for developers to profit from the administratively-determined avoided costs to be approved by this

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[6] *See* 16 U.S.C. § 824a-3(a), (d).
[7] S.C Code Ann. § 65-41-10(2).
[8] SBA Burgess Direct, at 13.

Commission. Moreover, as I highlight above, Duke is, in fact, enabling real competition through procurement of significant new renewable energy capacity under Duke's CPRE Program. Solar generation procured through CPRE is actually based upon competitively determined pricing offered at or below long-term avoided costs, thereby achieving the benefits of the competitive market forces being touted by Mr. Burgess. Mr. Brown more fully addresses why it is inappropriate for the Commission to consider SBA's rhetoric regarding potential "cost overruns" of utility owned and constructed generation, and I will simply reiterate that Mr. Burgess' position fails to recognize the Commission's oversight of the planning and siting of new utility generation and the fact that the Commission limits recovery of utility investments placed in to service for customers to costs that are reasonable and prudently incurred.

Further, consideration of these generalized risks is inappropriate because avoided cost rates should be limited to costs forecasted to be incurred by the utility that are quantifiable and "real." In a 1995 Order rejecting aspects of California's PURPA implementation framework as inconsistent with PURPA, which Witness Brown discusses in his Rebuttal Testimony, FERC explained that a "state may not set avoided cost rates or otherwise adjust the bids of potential suppliers by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities decision."[9] Thus, costs or risks that are speculative, or otherwise not costs actually being avoided as a result of the QF delivering power

[9] *See Southern California Edison*, 71 F.E.R.C. ¶ 61, 269, 62,080 (June 2, 1995). *See also Cal. Pub. Utility Comm'n.*, 132 FERC ¶ 61, 047, 61,267-68 (July 15, 2010), *clarification granted & rehearing denied*, 133 FERC ¶ 61, 059 (October 21, 2010),

to the purchasing utility are inappropriate to consider in arriving at the utility's avoided costs.

To my knowledge, taking such generalized and speculative risks—which Mr. Burgess makes no attempt to quantify as impacting future system costs—into the calculation of avoided cost rates under PURPA would be unprecedented and, in my opinion, prohibited by both PURPA and Act 62. Accordingly, the Commission should reject Mr. Burgess' novel "zone of reasonableness" theory as inappropriate and inconsistent with the standards established for setting avoided costs rates under PURPA and Act 62.

Q. WHICH ENTITIES DO HAVE A DIRECT FINANCIAL INTEREST IN THE AVOIDED COST RATES APPROVED IN THIS DOCKET?

A. The solar QF development industry has a direct and substantial interest in avoided cost rates being set as high as possible to enable the highest profits for QF developers and their investors, which are paid for by the utility's customers. SBA Witness Davis (a Vice President at solar developer, Southern Current) interestingly volunteers that SBA is not incentivized to promote setting avoided cost rates as high as possible.[10] However, it is unquestionably true that QF developers' profits are directly tied to avoided cost rates. Clearly, the representatives of the solar community in this proceeding are the true parties with a financial interest in the outcome of this case. Since the administratively-determined projections of avoided cost rates established in this proceeding are fixed and irrevocable (as opposed to being based upon cost of service or competitively based), interveners representing

[10] SBA Davis Direct, at 15-16.

QF developers can add substantial profit to their projects by obtaining higher administratively determined avoided cost prices through this proceeding. For this reason, I recommend the Commission carefully consider the "methodological choices" that Mr. Burgess proposes on behalf of the solar industry to artificially raise Duke's avoided cost rates. As I highlight throughout my testimony, Mr. Burgess' often superficial analysis and recommendations to adopt costs or policies from other jurisdictions (many of which are not even used to calculate avoided costs) all have only one thing in common: they are designed to increase the future revenues that customers will pay to solar QFs, if adopted.

While Mr. Burgess implies that it is Duke that has made specific methodological choices with the intent of lowering avoided cost rates, the Commission will find through a comprehensive review of Mr. Burgess' testimony that his "adjustments" each represent methodological choices designed to artificially raise rates. Furthermore, he often uses loose references to other utilities in jurisdictions such as California, Minnesota and Virginia and selectively highlights an issue as a rationale for adopting higher avoided costs without actually stating if utilities in that jurisdiction apply the same adjustment Mr. Burgess recommends in setting their own avoided costs. In each instance Mr. Burgess has made specific "methodological choices" that in total would significantly and inappropriately increase avoided costs.

Finally, it is important to recognize that customers also have a direct financial interest in ensuring the avoided cost rates this proceeding most accurately reflect Duke's future avoided costs. Each dollar of QF purchase expense is a direct cost to consumers, which is why avoided cost rates should not be set based on anything other than the actual costs that are being offset from QF purchases.

Q. DOES MR. BURGESS ADDRESS THE POTENTIAL COST IMPACTS TO DUKE'S CUSTOMERS IF HIS HIGHER AVOIDED COST RATES ARE ADOPTED.

A. Not completely. Interestingly, Mr. Burgess's Direct Testimony does specifically raise this issue at page 19, but then he essentially dodges his own question. His answer does not address what the total impact of his proposed avoided cost rates would be on Duke's customers. Instead, he points to the rate impact if the Commission were to decide not to adopt the Integration Services Charge without considering the impact of his proposals to significantly increase DEC's and DEP's avoided energy and capacity rates. He suggests that "even in the most extreme case, the inclusion of Duke's proposed integration charge will potentially save SC customers <1% on their electric bills."[11] As the Commission will surely recognize, any increase to customer electric bills to cover the ancillary service costs not assigned to the solar QF cost causer may be small when looked at in isolation. However, given the uncertainty in the volume of QF purchases in question, and uncertainty in the total increase Mr. Burgess is suggesting, the impact he refers to could easily be in the tens to hundreds of millions of dollars annually paid for by customers. This would represent a direct subsidy from customers to the QF industry if the avoided cost rates fail to accurately and appropriately recognize the value of QF solar being delivered to customers. As

[11] SBA Burgess Direct, at 19-20.

Duke Witness Brown highlighted in his Direct Testimony, the costs of QF power are a wholesale purchased power expense that is simply passed through to customers under the Companies' fuel clause. Therefore, I believe the Commission should reject the assumption made by SBA Witness Burgess that any "zone of reasonableness" should apply, and even if it did, customers should not be paying for the high end of the "zone of reasonableness."

III. <u>AVOIDED ENERGY</u>

a. <u>Avoided Energy Rate Cost Calculation</u>

Q. PLEASE BRIEFLY DESCRIBE THE METHODOLOGY AND INPUTS THAT DUKE USED TO CALCULATE THE SCHEDULE PP AVOIDED ENERGY RATES.

A. As explained in my Direct Testimony, the Companies utilize the peaker methodology to calculate avoided energy costs which are then converted to the avoided energy rates filed in this docket. Under the peaker methodology, avoided energy costs are estimated using a production cost simulation model, PROSYM[12], to analyze the change in system production costs with and without a 100 MW block of no-cost generation on an hourly basis over a 10-year period corresponding to the Companies' most recent IRPs. First, the production cost model simulates a "base case" of estimated variable production costs, which is then compared to a second, identical simulation that includes a hypothetical 100 MW of no-cost generation added to the utility's generating fleet. This 100 MW of no-cost generation

[12] PROSYM is an hourly chronological model that dispatches generating units in a least cost manner subject to various constraints such as scheduled maintenance of generating units, transmission import limitations, spinning reserve requirements, generation ramp rates, and minimum run times.

represents QF power capable of displacing energy that was generated from the marginal unit or units in the base case, resulting in lower overall variable production costs in the second case. Importantly, as I describe in more detail later in my Rebuttal Testimony, marginal units often refer to units that have the ability to increase rates to generate another 1 MW of energy, but in the context of avoided costs, marginal units are those units that can reduce their output to accommodate the 100 MW of no-cost generation. The decrease in hourly production costs from the base case to the second, or change case that includes the 100 MW of no-cost generation represents the marginal energy costs that can be avoided over the 10-year period. These avoided hourly energy costs are then used to calculate avoided energy rates consistent with the goal of leaving customers indifferent between QF power purchases and generation provided by the utility.

Q. DOES THE ORS AGREE WITH THE COMPANIES' PROPOSED AVOIDED ENERGY RATES?

A. Yes. ORS Witness Horii states that "[b]ased on [his] review, the avoided energy costs reflected by the Companies in the Standard Offer tariffs are a reasonable result of the Companies' calculations. The calculation methodology is consistent with PURPA and the Commission's prior approval."

Q. DID INTERVENORS ON BEHALF OF THE SOLAR INDUSTRY ARGUE THAT THE COMPANIES' AVOIDED COST RATES SHOULD BE INCREASED?

A. Yes. As I explained above, intervenor Witnesses on behalf of the solar industry in this proceeding have a financial interest in driving up avoided cost rates—including avoided energy rates—to enhance the profitability of their QF projects. Accordingly, SBA Witness Burgess argues that the Companies' avoided energy cost calculations are erroneously low and advocates for higher avoided energy rates. However, the primary question before the Commission is what are the true energy costs that are being avoided when QF purchases are made by DEC and DEP? The peaker methodology applied by the Companies is designed to answer this question and to reasonably ensure that customers remain indifferent to the forecasted avoided energy rates established in this proceeding.

Q. WHAT ARGUMENTS DOES SBA PUT FORTH TO ARGUE THAT THE COMPANIES' AVOIDED ENERGY RATES SHOULD BE HIGHER?

A. SBA Witness Burgess raises four main concerns with the Companies' avoided energy cost calculations to advocate for alternative, higher avoided energy rates. He first argues that the Companies' hourly modeling results incorrectly illustrate a significant fraction of hours that have negative avoided costs, which he further argues are an "artefact" of Duke's modeling "rather than what is likely to occur in real-world operations."[13] He then takes issue with the Companies' fuel and commodity costs, arguing that coal is often on the margin in DEC and DEP-East while a future combined cycle ("CC") gas unit is only primarily on the margin in DEP-West.[14] In doing so, he also recommends that separate regional avoided cost rates be calculated for DEP-East. Witness Burgess then argues that a fuel hedge,

[13] SBA Burgess Direct, at 22-23.
[14] The NERC-official names of the Duke Energy Progress Balancing Authority Areas are "CPLE" and "CPLW." Duke is using DEP-East and DEP-West for ease of reference.

as well as an environmental cost adder, be included in the Companies' avoided energy rates to further increase the avoided cost rates paid to QF developers.

Q. HOW DO YOU RESPOND TO SBA WITNESS BURGESS' ARGUMENT THAT DUKE INCORRECTLY PROJECTED NEGATIVE AVOIDED COST VALUES IN ITS MODEL?

A. Witness Burgess suggests that "[c]onstraints built in [Duke's] model such as transmission limits, generator minimum loading levels, generator ramp rates, and so on may bear no relation to real-world conditions or the actual operation of Duke's system," to argue that Duke's avoided energy rates are above Duke's marginal value of energy.[15] However, as I explain in greater detail below, negative avoided costs occur for a variety of reasons when QF energy is added to the system. For example, the inclusion of no-cost QF energy can shift combustion turbine ("CT") starts from one hour to the next, thereby creating an instance where a start cost is avoided in one hour but the cost is then incurred in the next hour. The addition of no-cost QF energy creates conditions that can lead to negative avoided costs in some hours that are seen in both the model, as well as on the actual Duke system. While no model can completely match "real-world" conditions, the precise operating conditions that Witness Burgess points out in his Rebuttal Testimony are, in fact, the "real-world" operating constraints of Duke's generation fleet and transmission system, and are accurately represented in the model. Notably, Witness Burgess admits that these constraints could actually represent "real-world" conditions of the Duke systems by carefully qualifying that the constraints "*may*

[15] SBA Burgess Direct, at 24.

not" represent "real world" conditions and agreeing that "it is possible" for avoided energy costs to be negative during some hours.[16]

Q. CAN YOU PROVIDE AN EXAMPLE OF OPERATIONAL REALITIES THAT EXPLAIN THE NEGATIVE HOURS MR. BURGESS IS CONCERNED ABOUT?

A. Yes. It is to be expected that certain operating conditions will cause both the model, and the actual Duke system, to operate with higher marginal costs for some hours of the year when 100 MW of no-cost generation is added to the system. Importantly, however, over the entire ten-year modeling period, the no-cost generation provides lower cost energy than in the same ten-year modeling scenario without the 100 MW of no cost generation—i.e. the base case—when all hours are considered collectively.

To demonstrate the impact of the 100 MW of no-cost generation, consider Figure 1 below. Figure 1 presents a simplified generation stack that consists of a single CC and a single CT during a summer afternoon in DEP.

Figure 1: Illustrative Example of DEP "Base Case" Generation Stack without QF Energy

Hour Ending		14	15	16	17	18	19	20	21
Energy Bucket		On Peak	On Peak	On Peak	Prem Peak	Prem Peak	Prem Peak	Prem Peak	On Peak
Hourly Demand, MW		*350*	*400*	*450*	*600*	*650*	*700*	*650*	*550*
Base Case - No QF Energy									
	500 MW CC	350	400	450	**500**	**500**	**500**	**500**	**500**
	200 MW CT	0	0	**Start**	100	150	200	150	50
	Total Generation	350	400	450	600	650	700	650	550

In this example, which illustrates the base case and therefore does not include the 100 MW of no-cost generation representing QF power, the CC ramps up as demand

[16] SBA Burgess Direct, at 25.

increases on the system. To continue to meet demand as the CC approaches maximum capacity, the CT must start up in hour 16:00, incurring a "start cost". While the CC is operating at maximum capacity, the CT continues to ramp up to meet increasing demand across the premium peak hours in Figure 1. Eventually, demand drops and the CT is no longer needed and is shutdown. Similarly, the CC is also ramped down to follow the decrease in demand.

Now consider the same example, but include the 100 MW of no-cost generation representing QF power as shown in Figure 2.

Figure 2: Illustrative Example of DEP "Change Case" Generation Stack with QF Energy

Hour Ending		14	15	16	17	18	19	20	21
Energy Bucket		On Peak	On Peak	On Peak	Prem Peak	Prem Peak	Prem Peak	Prem Peak	On Peak
Hourly Demand, MW		*350*	*400*	*450*	*600*	*650*	*700*	*650*	*550*
Change Case - 100 MW QF Energy									
	Flat 100 MW QF	100	100	100	100	100	100	100	100
	500 MW CC	250	300	350	**500**	**500**	**500**	**500**	450
	100 MW CT	0	0	0	**Start**	50	100	50	0
	Total Generation	350	400	450	600	650	700	650	550

In this change case, the QF is generating maximum output throughout all hours leading up to the premium peak hours. The CC's output is commensurately reduced and the CT is no longer required to start up in hour 16:00 as was the case in Figure 1, thereby saving both fuel costs and a CT start cost. However, as demand (load) continues to increase, the CC reaches maximum output and the CT must start up in hour ending 17:00 in order to meet system demand, thereby requiring a startup cost to be incurred in that hour. In looking to Figure 2, since the 100 MW of no-cost generation allowed the CT start up to shift from hour 16:00 to 17:00, the production cost model would show a negative avoided cost value in hour 17:00. The reason for the negative value is simply because hour 17:00 in the change case with the inclusion of QF energy is now more expensive than hour 17:00 in the base case without the QF energy due to the additional start cost incurred in that hour. Therefore, while Mr. Burgess accurately picks up on the negative value produced in one hour, he fails to recognize the offsetting benefit that occurred in the prior hour when making his claim. This shifting of startups when additional generation is added to the system occurs frequently in the production cost model as well as in the "real-world" during Duke's actual system operations. The shifting of generator startups is a fairly well understood aspect of production cost modeling of this type and it is surprising that Mr. Burgess is attempting to characterize this aspect of the modeling as somehow inappropriate.

Another factor that frequently drives negative hours, in DEC in particular, is changes in the hours that the Jocassee and Bad Creek Pumped Hydro assets pump and discharge water. With the addition of 100 MW of no-cost generation, the production cost model will see changing hours of pumping and discharging water resulting in some negative hours between the base and the change case. Again, this simply represents a shift in the system dispatch that has an overall positive avoided cost value even if certain hours viewed in isolation are negative.

In summary, there are hours of negative avoided cost value that are consistent with "real world" system operation and are accurately simulated in the production cost model when QF energy is added to the system. To discount those negative hours as "an artefact of Duke's modeling" when calculating the avoided energy rate would incorrectly inflate the avoided energy cost value that QFs provide to the Companies' customers. As such, Witness Burgess' claim should be dismissed.

Q. ARE DUKE'S PROPOSED NATURAL GAS AND COAL PRICES APPROPRIATE FOR BOTH DEC AND DEP?

A. Yes. ORS Witness Horii points out in his Direct Testimony that he "reviewed the fuel price forecasts and other variables the Companies incorporated in calculating the avoided energy costs for both the 2016 and 2019 avoided cost proceedings" and "[t]he forecast methodologies and values are consistent with market knowledge of fuel price forecasts and generator cost forecasts available at the time of the Companies' forecasts."[17]

Q. SBA WITNESS BURGESS STATES THAT COAL IS MOST OFTEN ON THE MARGIN IN BOTH DEC AND DEP-EAST WHILE GAS IS MOST OFTEN ON THE MARGIN IN DEP-WEST. DO YOU AGREE WITH HIS CHARACTERIZATION?

A. No, I do not. Witness Burgess took issue with my Direct Testimony that natural gas is "often the marginal resource" and then proceeded to incorrectly use model data to claim that, to the contrary, coal is more often the marginal resource in DEC and DEP-East. Based on this claim, he stated that "the commodity prices that Duke uses for both coal and natural gas have a significant influence on the avoided energy cost rate, making it very important to closely examine Duke's assumptions about these prices."[18]

[17] ORS Horii Direct, at 9.
[18] SBA Burgess Direct, at 28.

As an initial matter, Witness Burgess is correct in that using accurate commodity prices is important when calculating avoided energy rates, and, as noted above, ORS Witness Horii agrees that the fuel prices used in these calculations by DEC and DEP are appropriate. Turning to Witness Burgess' conclusion that coal assets are the marginal resources in DEC and DEP-East, it is important to highlight two issues with his explanation of the model data, as his interpretation can lead to confusion when evaluating the appropriateness of the Companies' avoided cost calculations. These issues are (1) Mr. Burgess' apparent misunderstanding of the terms "marginal unit" or "marginal resource" in the context of how avoided energy costs are calculated, and (2) his misunderstanding of how the DEP-East and DEP-West Balancing Authority Areas ("BAAs") are interconnected.

First, Witness Burgess' interpretation of the model output data highlights potential confusion around the terms "marginal unit" or "marginal resource" when calculating avoided energy costs. Under the peaker methodology, marginal system energy benefits are determined by comparing a base case production cost run to that of an identical run with the addition of a 100 MW no-cost generation resource available in each hour of the year. In my Direct Testimony, "marginal resource" refers to the marginal avoidable generating units that reduced output when the 100 MW no-cost generation resource was added to the system in the change case. This definition of "marginal resource" should not be confused with the system lambda or what is sometimes referred to as the "marginal cost" in production cost models. System lambda represents the cost of the marginal generating unit that can increase its output to supply the next 1 MW.

For example, as Witness Burgess points out, coal units may set the system lambda for a significant portion of time. However, these units have cycling restrictions and must-run restrictions that keep them online at or near their minimum output for much of the time. These cycling restrictions and must run restrictions often prevent them from reducing their output when additional generation is added to the system. Duke Witness Sam Holeman describes the must run requirements and operating restrictions as informing the "Lowest Reliable Operating Limit" or "LROL" for each generating facility. In this manner, coal may often be represented as the marginal unit, but, as shown in Figures 3 and 4 below, for purposes of calculating avoided energy, the marginal units that are most often on line and have the flexibility to reduce output to accommodate the 100 MW of free energy are gas units.

Figure 3: DEP Avoided Fuel Burn with Addition of 100 MW Free Energy Resource

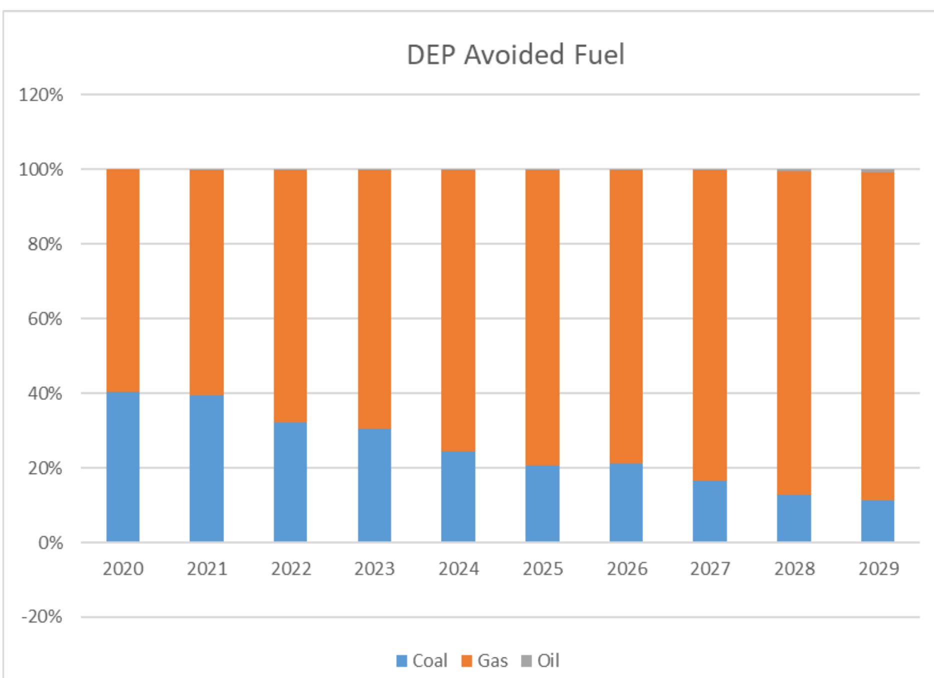
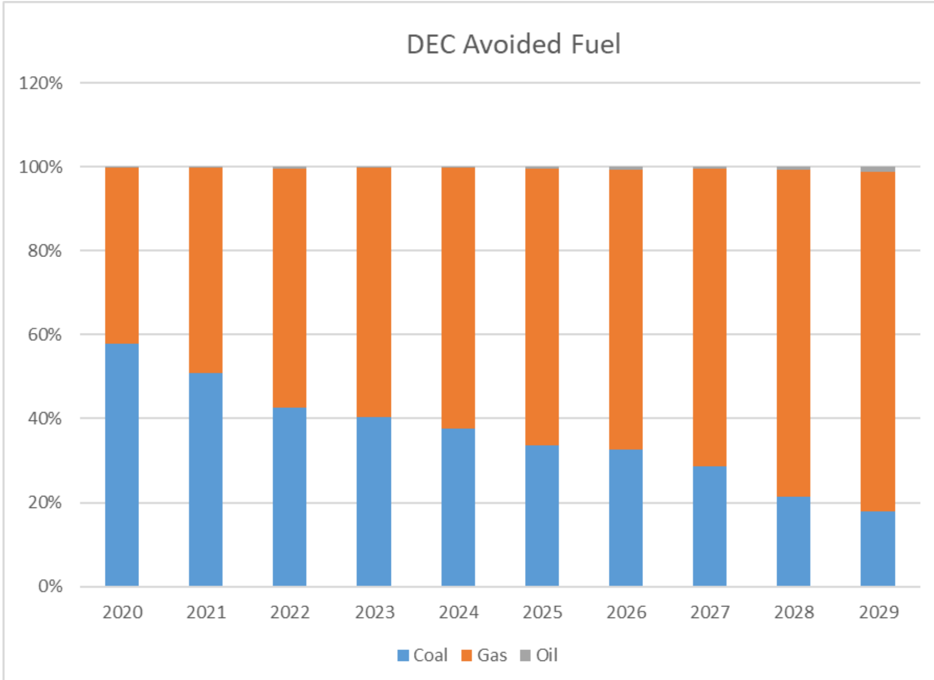


Figure 4: DEC Avoided Fuel Burn with Addition of 100 MW Free Energy Resource



Therefore, Witnesses Burgess' assertion that coal is the marginal resource that QF purchases can avoid most often in DEP-East and DEC is incorrect.

Q. DOES WITNESS BURGESS ACCURATELY INTERPRET THE MODEL DATA TO SUGGEST THAT THERE ARE SEPARATE MARGINAL AVOIDABLE RESOURCES IN THE DEP-WEST AND DEP-EAST BAAs?

A. No. The second issue with Witness Burgess' interpretation of the model data and results is how energy that is generated in the DEP-East and DEP-West BAAs can serve load outside of the territory in which the energy was originally generated. As explained in greater detail by Duke Witness Holeman, the DEP-East and DEP-West BAAs operate as a single DEP NERC Balancing Authority, and are interconnected through firm transmission interconnects that allow integrated system dispatch of all fleet generating units in DEP-East and DEP-West to serve load in both DEP-West and DEP-East. Since DEP operates as a single regulated utility and Balancing Authority with two BAAs that are connected by a firm transmission path, DEP system operators economically commit and dispatch the total resources in both DEP-East and DEP-West to meet the total load of both BAAs. For example, if DEP-West has load greater than the capability of the combined cycles located in the DEP-West BAA, the system operator will economically dispatch DEP-East resources to serve DEP-West load before running more expensive simple cycle CTs located in DEP-West. Thus, Mr. Burgess is simply incorrect in assuming that placing a QF in DEP-East will result in one set of marginal resources while placing the QF in DEP-West will result in another.

Q. PLEASE RESPOND TO SBA WITNESS BURGESS' ARGUMENT THAT A SEPARATE REGIONAL AVOIDED COST RATE SHOULD BE CALCULATED FOR THE DEP-EAST BALANCING AUTHORITY AREA.

A. SBA Witness Burgess again relies on his interpretation of the marginal generation model data to claim that since coal generation appears to be on the margin in DEP-East the majority of the time, and gas generation appears to be on the margin in DEP-West the majority of the time, that the two DEP BAAs should have separate regional avoided cost rates.[19] Witness Burgess further recommends that since DEP-West does not include South Carolina territory, the avoided cost rates in South Carolina should solely be based on DEP-East rates where SC customers are located. As I explained earlier in my Rebuttal Testimony, and as expanded further in Duke Witness Holeman's Rebuttal Testimony, these arguments show a misunderstanding

[19] SBA Burgess Direct, at 35.

of how the DEP system operates, as well as some confusion around the term "marginal unit" in the context of calculating avoided energy rates. To reiterate, the DEP BAAs are interconnected through firm transmission that allows energy generated in DEP-East to flow into DEP-West and generation that is generated in DEP-West to flow into DEP-East. As Duke Witness Holeman explains, from an operations perspective, this firm transmission of energy is no different from native load resources in North Carolina, such as the H.F. Lee Combined Cycle generator located in Goldsboro, NC (in the DEP-East BAA), reliably serving load for the DEP customers in both North Carolina and South Carolina, including the DEP-West BAA. The electrons generated in DEP-West, whether they are generated from solar QFs or CCs, will flow to meet demand via transmission wires to customers across both North Carolina and South Carolina.

Additionally, as I explained previously, the fact that coal is often the "marginal resource" in DEP-East is of little consequence in the calculation of avoided energy rates. Coal generators frequently have must run requirements or cycling restrictions that require the unit to be at or near its LROL minimum operating capacity which limits the unit's ability to reduce generation when QF energy is added to the system. The units that have the ability to reduce output when QF energy is added are frequently gas units as shown earlier in Figures 3 and 4.

Q. ARE THERE OTHER REASONS THAT ADOPTING WITNESS BURGESS' RECOMMENDATION FOR CALCULATING AVOIDED ENERGY RATES SOLELY FOR THE DEP-EAST BAA WOULD BE INAPPROPRIATE?

A. Yes. In addition to being inconsistent with how DEP operates its generating fleet, Witness Burgess' recommendation would also be inconsistent with PURPA's imposition of the mandatory purchase obligation on each "electric utility" under 18 C.F.R. 292.303. PURPA does not distinguish between the electric utility's operations in one state versus another for purpose of quantifying the electric utility's avoided costs.

It would also be inconsistent with general ratemaking principles for DEP and the other vertically integrated utilities in South Carolina, which recognize that generation units serve the entire customer base even if the utility spans two states. For example, nuclear resources in SC are used to serve customer load in both SC and NC just as renewable resources in NC are used to serve both NC and SC customer load. Accordingly, the costs of those resources are shared by all customers in both states and not allocated only to the customers in the state where the resource is located.

Q. WHY IS IT INAPPROPRIATE TO INCLUDE A SEPARATE FUEL HEDGE VALUE IN THE COMPANIES' AVOIDED ENERGY RATES AS GENERALLY RECOMMENDED BY SBA WITNESS BURGESS?

A. Purchasing QF power does reduce the amount of fuel purchased by the utility, and avoided fuel makes up a large component of the avoided energy rate. Importantly, however, the avoided fuel cost used in the avoided energy rate calculation represents the price of the fuel that Duke would otherwise have purchased if the Companies were to generate energy itself rather than purchasing fixed price QF power. As I mentioned earlier, the objective of fixing avoided costs is to quantify the incremental cost of alternative energy that "but for the purchase from such [QF], such utility would generate or purchase from another source." The fuel required to generate the equivalent amount of energy is the fuel being avoided. Moreover, when prices are established in any avoided cost proceeding, they represent a price that QFs have an option to receive, while the Companies and their customers have an obligation to pay the QF at the QF's sole discretion. This arrangement essentially represents the QF owning a "Put Option" from the Companies and their customers. A "Put Option" in this instance gives the option owner (QFs) economic exercise rights without the obligation to sell power, while the option seller (the Companies and their customers) have an economic obligation to purchase the QF power, but with no rights to deny purchase irrespective of prevailing market prices at the time of exercise. To the benefit of the QFs in this proceeding, the Companies have not quantified the "put premium" as a separate charge or reduction in the avoided energy rate.

Q. WITNESS BURGESS QUESTIONS WHETHER "REDUCED COAL ASH COSTS" WERE INCLUDED IN DUKE'S PROPOSED AVOIDED ENERGY RATES.[20] HAS DUKE APPROPRIATELY INCLUDED AVOIDED ENVIRONMENTAL COSTS, SUCH AS O&M COSTS TO MANAGE COAL ASH IN CALCULATING THE COMPANIES' AVOIDED ENERGY RATES?

A. Yes. Projected environmental costs associated with NO_x and SO_2 emissions, as well as coal ash handling costs at the existing coal units are included in the production cost model. In the model output, future coal ash handling costs are included as a component of the individual coal plant VOM costs. As I illustrated previously, the majority of energy being avoided by the QF is energy generated from natural gas, but to the extent that a QF avoids generation from coal plants, those environmental cost savings are included in the Companies' avoided energy rates. Importantly, the addition of QF energy on the system has no impact on historic coal ash costs. In other words, the cost associated with managing coal ash that was generated before QF energy materialized on the system cannot be reduced by future QF energy additions. The only coal ash costs that can potentially be avoided by QFs are the going-forward costs described above.

Q. PLEASE SUMMARIZE WHY IT IS INAPPROPRIATE TO ADOPT SBA WITNESS BURGESS' PROPOSED ADJUSTMENTS TO THE COMPANIES' AVOIDED ENERGY CALCULATIONS.

A. As explained above, negative avoided costs are appropriately modeled in the Companies' production cost model. Moreover, based on the fact that DEP-East

[20] SBA Burgess Direct, at 33.

and DEP-West are interconnected, and understanding that while coal may be generating the "marginal energy" in DEP-East the actual avoided energy is more often natural gas, Witness Burgess' recommendations to solely base DEP's avoided energy rates on marginal coal that is not avoided in DEP-East should be rejected. Additionally, it is inappropriate to include a fuel hedge in avoided energy rates since QFs do not actually provide a hedge. Finally, coal ash handling costs are already included in coal plant VOM costs, so to the extent that any coal generation is avoided, coal ash handling costs are already included in the avoided energy rates submitted by the Companies. Therefore, Witness Burgess' alternative avoided energy cost calculation should be rejected.

b. <u>Avoided Energy Rates for Large QFs Ineligible for the Standard Offer</u>

Q. PLEASE ADDRESS SBA WITNESS BURGESS' ARGUMENT THAT APPLYING A SOLAR-SPECIFIC GENERATION PROFILE FOR LARGE QFS IS UNREASONABLE AND THAT AVOIDED COST RATES SHOULD BE KEPT "TECHNOLOGY-NEUTRAL" ACROSS ALL QF CONTRACTS.

A. Witness Burgess argues that "avoided energy rates for each type of QF should be technology neutral" when arguing against a solar specific rate for larger QFs; however, he apparently only takes this stance when he perceives that it is in the financial interest of the solar QF. As an example, Witness Burgess criticizes the nine pricing periods for the Companies' avoided energy rates as "arbitrarily reduc[ing] the avoided energy cost rate during several key solar QF production hours by averaging these hours with lower value hours."[21] He goes on to suggest

[21] SBA Burgess Direct, at 37.

that "[a] different selection of pricing periods would more accurately reflect avoided cost and could significantly affect solar compensation."[22] Witness Burgess is essentially arguing to modify the Companies' avoided energy rate design by focusing on the specific operating characteristics of solar QFs while shifting compensation away from hours when the Company and its customers see the most value for the energy delivered by the QF. In contrast, as explained in my Direct Testimony, the Companies' intent in applying a solar-specific generation profile for solar QFs is to further ensure that the avoided energy rates calculated for non-Standard Offer PPA QFs most precisely equal the Companies' actual avoided cost, consistent with both PURPA and Act 62.

Q. WITNESS BURGESS' COMMENTS THAT A TECHNOLOGY-SPECIFIC APPROACH TO CALCULATING AVOIDED ENERGY COSTS FOR LARGE NON-STANDARD OFFER SOLAR QFS IS NOT APPROPRIATE FOR SOLAR QFS THAT INSTALL ENERGY STORAGE. DO YOU AGREE?

A. This is a fair point, and Duke agrees that a QF that designs its facility to integrate energy storage and commits to operate its facility in a controlled manner that does not reflect the generator profile of an uncontrolled and intermittent solar QF should be eligible for avoided energy rates calculated using a load-profile that reflects the characteristics of the storage device utilized by the QF. However, the Companies continue to support applying a solar-specific generation profile for large solar QFs

[22] *Id.* at 39.

not eligible for the Standard Offer in order to most precisely calculate the avoided energy value these QFs are delivering to the system.

Q. HAS FERC RECOGNIZED THAT IT IS APPROPRIATE TO TAKE THE SPECIFIC CHARACTERISTICS OF A NEGOTIATED PPA QF INTO ACCOUNT WHEN CALCULATING AVOIDED COSTS?

A. Yes. FERC's regulations governing the rates for purchase from QFs establish a number of factors in 18 C.F.R. 292.304(e) relating to the supply characteristics of the QF that should be taken into account "to the extent practical" in determining avoided costs. Specific to intermittent QFs, FERC has also more recently recognized that utilities may take the QF's supply characteristics into account, including, among others, the availability of capacity, the QF's dispatchability, the QF's reliability, and the value of the QF's energy and capacity.[23] Notably, this aligns with Act 62's provision that avoided cost methodologies approved by the Commission "may account for differences in costs avoided based on the geographic location and resource type" of the QF. [24]

Q. DO OTHER UTILITIES SIMILARLY ACCOUNT FOR THE SPECIFIC CHARACTERISTICS OF LARGER QFs NOT ELIGIBLE FOR THE STANDARD OFFER WHEN CALCULATING AVOIDED ENERGY COSTS?

A. Yes. The Companies understand that Dominion Energy South Carolina ("DESC"), formerly known as SCE&G, calculates its avoided energy rates based on a solar-

[23] *Windham Solar, LLC*, 157 FERC ¶ 61,134 (2016).
[24] 58-41-20(B)(3).

specific load shape profile. In May 2018, the Commission found that Dominion Energy South Carolina's proposal "to use a 100 MW solar profile to calculate avoided costs is warranted and appropriate."[25]

In Montana, rates for QFs larger than 3 MW are also "determined based on the facilities' individual performance characteristics, including their unique electricity production profiles."[26] In a 2017 Order approving this practice, the Montana Public Service Commission explained:

> The purpose of [Montana's regulations establishing standard offer rates for QFs up to 3 MW in size] and [the] federal regulations is to prevent large QFs from simply photocopying the rate another QF with different production and a different vintage has obtained, and instead ascertaining more specifically what an appropriate avoided-cost rate is. In this case, [the large QF ineligible for the standard offer's] assertion that its facility has the same avoided energy cost value approved in [a case concerning a QF 3 MW or less eligible for the Montana standard offer] is effectively a demand for a standard rate, *i.e.*, a rate applied to a generic class of generators and not based on a project's individual performance characteristics. However, the ***Commission finds that the supply characteristics and aggregate value of energy from [the large QF] are, in fact, individual and unique, and that simply adopting [the standard offer QF's] avoided energy cost for [the QF ineligible for the standard offer] would not be just and reasonable to [the utility's] customers***.[27]

[25] *Amended Order Approving Fuel Costs,* Order No. 2018-322(A). at 28, Docket No. 2018-2-E (May 2, 2018).

[26] *In the Matter of the Petition of Crazy Mountain Wind for the Comm'n to Set Certain Terms & Conditions of Contract Between Nw. Energy & Crazy Mountain Wind, LLC.*, No. 7505C, 2017 WL 1425719, at *6 (Apr. 18, 2017).

[27] *Id.*

Q. SBA WITNESS BURGESS RAISES CONCERNS THAT DUKE'S PLAN TO APPLY THE SPECIFIC SUPPLY CHARACTERISTICS OF THE LARGE SOLAR QFs IS LIKELY TO INCLUDE METHODOLOGICAL CHOICES THAT HAVE NOT BEEN MADE TRANSPARENT IN THIS PROCEEDING. PLEASE REITERATE THE SPECIFIC SUPPLY CHARACTERISTIC THAT DUKE IS PLANNING TO TAKE INTO ACCOUNT WHEN CALCULATING AVOIDED COSTS FOR A NEGOTIATED PPA QF?

A. As generally explained in my Direct Testimony, in calculating avoided cost for Large QF PPAs, the Companies will take into account the production profile of the facility when calculating their avoided costs. Specifically, solar QFs or solar QFs with integrated battery storage, will be required to supply an hourly energy production profile that will be used in place of the flat 100 MW no-cost generation profile that is used when calculating the standard offer avoided energy rates. Additionally, consistent with the Companies' historic practice, the Companies will also apply the most up-to-date inputs under the peaker methodology (such as updates to the current market prices to reflect the current market value of fuel, as well as updates to reflect any changes to the Companies' resource plan to be consistent with the most recently-filed IRPs) in order to more accurately align the avoided cost rates paid to the QF with the value provided to customers. Importantly, these updates are transparent inputs to the model that can have the effect of raising the avoided cost value paid to the QF with equal likelihood as lowering the value paid to the QF.

c. Avoided Energy Rate Design

Q. DOES SBA WITNESS BURGESS PROPOSE MODIFICATIONS TO THE COMPANIES' AVOIDED ENERGY RATE DESIGN?

A. Yes. Witness Burgess is critical of the pricing hours recommended by Duke in its proposed avoided energy rate design basically because the pricing hours fail to align with the hours of maximum solar generation. He argues that the hours grouped within each pricing period are subjective and can be skewed to harm solar generation. In particular, he suggests that the off-peak hours are overly broad and include hours when solar generation would be available and that by grouping these hours in this manner, all of which have a lower than average cost for that season, that solar QFs are being disadvantaged.[28] He suggests re-designating a certain number of these low cost of service hours into a separate pricing period so that the peak hours better coincide with solar generation operations. In doing so he ignores the fact that the design is primarily configured to offer higher prices during times of higher value to retail customers in order to incent QF generation to deliver energy during these periods.

Q. DO YOU AGREE WITH SBA WITNESS BURGESS' ASSESSMENT?

A. No. The proposed avoided energy hours were determined using a methodology that considers the Companies' cost to serve customers in each hour of the day, week, and season, and appropriately reflects natural groupings of hours with similar cost attributes. The Companies' design provides additional granularity, beyond the pricing periods reflected in the presently approved purchased power schedule, to

[28] SBA Burgess Direct, at 37-38.

more clearly identify the hours where QF generation would be of most benefit to retail customers. Specifically, the Companies employed a three-step rate design approach that considers the factors that best reflect the Companies' individual avoided cost based upon seasonal and time-of-day characteristics. The benefit of this design is that QFs will be provided improved price signals that are better aligned with the Companies' cost to serve retail customer generation needs.

Q. SHOULD THE ANTICIPATED HOURS OF PRODUCTION OF CERTAIN TYPES OF GENERATION BE CONSIDERED WHEN DEVELOPING THE RATE DESIGN?

A. No. The energy rate design should reflect the Companies' cost of service and system needs, as well as encourage QF generators to adjust their operation to maximize their production during hours that are most beneficial to retail customers and therefore, the system as a whole. The rate design hours also must be granular enough to provide clear price signals regarding the future value of generation to QFs, but also not be so specific that the defined pricing periods shift with the smallest movement in forecasted inputs. This balance is an important consideration to undertake when the rate design will remain in effect for multiple years under a fixed-price purchased power agreement.

The rate design must also be administratively manageable to ensure accuracy in billing while minimizing potential confusion for QFs caused by frequent price changes. The key question when evaluating a rate design is whether the design properly incents the correct behavior relative to the Companies' marginal cost of service in order to leave retail customers unharmed by QF purchases. This is particularly important during periods when rates are high indicating a high value to retail customers. A properly developed avoided cost rate design based on the underlying utility's marginal cost provides an economically efficient price that leaves the consumer indifferent to utility generated power or QF delivered power.

Q. DOES THE COMPANIES' PROPOSED RATE DESIGN MEET THE OBJECTIVE OF PROVIDING AN ECONOMICALLY EFFICIENT PRICE SIGNAL?

A. Yes. The avoided energy payment rate designs provide sufficient seasonal and hourly granularity and appropriate price signals and incentives for QFs to maximize output during times when energy has the most value to the Companies and their customers. The proposed rate structure and rates should leave retail customers indifferent to the source of generation, whether it was produced by the QF or from other Duke resources. The Companies believe that the rate design fairly balances all considerations in a manner that appropriately reflects cost causation and offers QFs the opportunity to adjust their production hours to maximize their financial benefit, in addition to being administratively manageable from a metering and billing perspective. The proposed rate design also conforms with the fundamental indifference or "but for" principle of PURPA, ensuring customers are not paying more than the actual costs avoided by the utility.

IV. AVOIDED CAPACITY

a. Avoided Capacity Cost Calculation

Q. WHAT WAS THE BASIS FOR THE COMPANIES' AVOIDED CAPACITY COST?

A. DEC and DEP each calculated their respective avoided capacity cost based on the cost of constructing combustion turbine capacity using publicly available data from the EIA. The EIA data reflects the cost to build a single, advanced F-class CT unit at a greenfield site. Given that the Companies' practice is to build multiple units at a new site, the Companies adjusted the EIA data to reflect the economies of scale associated with land, buildings, roads, security, gas interconnection and other infrastructure for a four-unit CT site.

Q. DO THE COMPANIES HAVE ANY F-CLASS CTS CURRENTLY IN-SERVICE?

A. Yes. The Companies have multiple F-class CTs in-service in simple-cycle mode at the Rockingham, Asheville, Smith and Wayne sites. The Companies also have F-class CTs in-service in combined-cycle mode at the Buck, Dan River, WS Lee, HF Lee, Smith and Sutton sites. In addition, DEP is currently constructing two combined-cycle units using F-class CTs at the Asheville site.

Q. DID ANY INTERVENORS EXPRESS CONCERN WITH THE COMPANIES' USE OF F-CLASS CTS AS THE BASIS FOR THE AVOIDED CAPACITY COST?

A. Yes. SBA Witness Burgess stated that Duke had selected the lowest cost available peaking unit and suggested that it does not necessarily correspond to the cost of the peaking unit that Duke would ultimately select to meet future peak demand or provide other services.[29] Mr. Burgess cited recent construction of aero-derivative CTs in the PJM region and stated there has been a growing trend towards more flexible, aero-derivative types of peakers.[30] Mr. Burgess further explained that the EIA cost assumptions are reasonable for a frame CT but are not reasonable for an aero-derivative CT or internal combustion engine. Mr. Burgess then made a rather arbitrary recommendation to use the midpoint of the Companies' F-class CT cost and Dominion Energy Virginia's aero-derivative CT cost studied in that utility's 2018 IRP to propose a capital cost assumption of $1,181/kW.[31]

Q. DID DOMINION ENERGY VIRGINIA USE AN AERO-DERIVATIVE CT AS A PROXY FOR THE COST OF CAPACITY AVOIDABLE BY A QF?

A. No. I will address Mr. Burgess' reference to Dominion Energy Virginia's IRP further below, but I would first note that neither Dominion Energy Virginia nor Dominion Energy North Carolina ("DENC") use an aero-derivative CT as the basis for its avoided cost rates. Dominion Energy Virginia relies upon the PJM real-time locational marginal price to set its avoided cost. DENC's most recently filed avoided cost rates in North Carolina Docket No. E-100, Sub 158 used a J-frame CT. In utilizing a J-frame CT, DENC filed a lower avoided capacity cost in North Carolina as compared to what the Companies have filed in this South Carolina proceeding. In addition, Dominion Energy South Carolina has also proposed a lower avoided capacity cost than the Companies in South Carolina, filing for

[29] SBA Burgess Direct, at 54-55.
[30] *Id.*
[31] *Id.* at 57.

Commission approval of an avoided capacity cost of zero for solar QFs subject to DESC's Standard Offer Rate in Docket No. 2019-184-E.[32]

Q. DO YOU AGREE WITH SBA WITNESS BURGESS' RECOMMENDED CAPITAL COST ASSUMPTIONS?

A. No. Returning to Duke's actual plans to construct future CTs in the Carolinas, DEC's 2019 IRP shows a block of two F-class CTs projected in 2026, 2031, 2032, 2033 and 2034. DEP's 2019 IRP shows two F-class CTs in 2028, eight CTs in 2029, two CTs in 2031, four CTs in 2033 and six CTs in 2034. Neither DEC nor DEP project the need for aero-derivative resources at this time. Aero-derivative CTs have a significantly higher capital cost than F-class CTs and are typically only constructed for power supply needs to satisfy specific, fast start or black start functions as was the case with DEP's recent aero-derivative CT additions at the Sutton plant. The Companies may need to add new fast start / black start capacity at some point in the future to replace unit retirements that currently provide those functions. However, as described below, even if the Companies had a niche need for aero-derivative CTs, it would inappropriate to use this technology as the basis for the avoided capacity cost under the peaker methodology.

Q. IS SBA WITNESS BURGESS' RECOMMENDATION TO USE A HIGHER CAPITAL COST CT CONSISTENT WITH THE PEAKER METHODOLOGY?

A. No. As explained in my Direct Testimony, the peaker methodology assumes that when a utility's generating system is operating at equilibrium, the installed fixed

[32] Direct Testimony of James Neely, at 12, Docket No. 2019-184-E (Aug. 23, 2019).

capacity cost of a simple-cycle combustion turbine generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF. Consistent with PURPA, the peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost.

Under the theoretical corollary of the peaker Methodology, even if a utility's next planned unit is not a simple cycle peaker, the peaker methodology still accurately represents a valid estimate of the utility's avoided costs. From an installed cost perspective, a simple cycle F-frame peaking unit is typically the least expensive type of traditional resource that the Companies can construct to provide capacity for reliability purposes. Building incremental peakers for capacity and relying on the remaining system for marginal energy is always an option within the resource planning process.

I do agree with Mr. Burgess that aero-derivative CTs could be a future way for the Companies to manage the intermittent output of must-take solar generators. In that event, however, the cost causer for the more expensive aero-derivative CT would be the solar providers themselves and thus, the incremental cost of constructing aero-derivative CTs versus F-class CTs should be paid by the solar providers and not paid for by customers to the solar providers. Since the current resource plan does not express the need for these more expensive aero-derivative turbines to respond to solar intermittency and ramping constraints, the Companies are not seeking to apply that cost to solar providers at this time.

Q. DID SBA WITNESS BURGESS' REFERENCE TO DOMINION ENERGY VIRGINIA'S IRP DISCUSS UTILIZATION OF AN AERO-DERIVATIVE CT IN CONJUNCTION WITH INTERMITTENT, NON-DISPATCHABLE SOLAR RESOURCES?

A. Yes. However, I would first note that Dominion Energy Virginia filed an update to its original 2018 IRP, which final 2018 IRP did not include aero-derivative CTs. Second, I would note that in addition to DENC not using an aero-derivative CT to calculate its avoided costs applicable to PURPA QFs, Dominion Energy Virginia also did not include an aero-derivative CT in its original, actual 2018 IRP Plan[33]. Instead, aero-derivative CTs were only included in Dominion Energy Virginia's Alternative High Solar Penetration Plans in its original 2018 IRP, where that utility identified the need for "a fast ramping and flexible generation resource that can effectively be paired with intermittent, non-dispatch renewable resources, such as solar and wind."[34] Therefore, Dominion Energy Virginia similarly recognized that the purpose of installing aero-derivative CTs is to assist in managing intermittent, non-dispatchable renewable QF resources.

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[33] Dominion Energy Virginia 2018 Integrated Resource Plan, at 3-4 (May 1, 2018), *available at* https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf.
[34] *Id.* at 72.

Q. SBA WITNESS BURGESS ALSO CRITICIZES THE ECONOMIES OF SCALE ADJUSTMENT THAT THE COMPANIES MADE TO THE EIA CT CAPITAL COST ESTIMATE. DO YOU AGREE WITH HIS ASSESSMENT?

A. No, I do not. To be clear, the Companies made adjustments to reflect the fact that it is more economic to build multiple units at a greenfield site to take advantage of economies of scale associated with sharing infrastructure and staff, rather than constructing a single CT at a greenfield site, which is the basis for the EIA estimate. The premise for the adjustments is that much of the same infrastructure would be required regardless of whether a single CT was built at a greenfield site or four CT units were built at a greenfield site. For example, the same land, roads, buildings, fire protection system, etc. would be required regardless of whether building a single unit site or a four-unit site. Thus, the infrastructure cost per CT would be lower for a four-unit site compared to a single CT site. The Companies' fully explained their practice of building multiple units at a site in response to SBA Interrogatory 3-9.

Mr. Burgess makes the following statements on page 58 of his Direct Testimony:

> Given its extraordinary size, I do not believe a 948 MW plant is representative of what Duke is likely to build in the near term to satisfy its peaking needs. Doing so would likely lead to a significant overbuild of capacity and a significant additional cost to customers.

For context, the 948 MW plant referenced by Mr. Burgess reflects building four CTs based on the EIA capacity rating of 237 MW per CT. It is important to note that the Companies distinguish between economies of scale (sharing the cost of infrastructure among multiple units) and economies of scope (building multiple units at the same time to realize economies associated with the mobilization and demobilization of equipment and personnel). Although the Companies' 2019 IRPs show a minimum of two CTs and a maximum of eight CTs being installed at one time, the Companies did not include any adjustments for economies of scope in the CT cost estimate.[35] Thus, the Companies' CT capital cost estimate does not include economies of scope associated with constructing multiple CTs at the same time. This information was also shared with Mr. Burgess in response to SBA Interrogatory 3-9.

Q. ARE TRANSMISSION SYSTEM UPGRADE COSTS INCLUDED IN THE CT CAPITAL COST ESTIMATE?

A. No. The EIA cost estimate includes an allowance for the plant switchyard and a connection to the transmission system but does not include significant transmission system upgrades.[36]

Q. DO YOU AGREE WITH SBA WITNESS BURGESS' RECOMMENDATION TO ADD $120/KW TO THE CT CAPITAL COST AS AN ASSUMPTION FOR TRANSMISSION SYSTEM UPGRADE COSTS THAT MAY OR MAY NOT BE REQUIRED?

A. No. Interconnection costs include costs associated with physically connecting the generation source to the transmission system, such as the switchyard and associated equipment costs. These interconnection costs are already included in the

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[35] DEC 2019 IRP, Table 8-A, at 52; DEP 2019 IRP, Table 9-A, at 59.

[36] EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants, Appendix B, at 2-7, *available at* https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

calculation of avoided cost rates because they are real costs that will be avoided when avoiding the construction of a new CT, and because the QF is fully responsible for the interconnection costs associated with its own facility.

Network system upgrade costs, unlike interconnection costs, involve improvements to the transmission system beyond merely connecting a generation resource to the transmission system. Such upgrades are needed to accommodate the anticipated increases in power flows as growing load is met from sources such as new generating facilities or new power purchases. Sometimes a utility's construction of new generation facilities will require transmission upgrades, but not all new generation additions require such upgrades. A number of factors, including the current state of the transmission system, the amount and type of generation being added to the system, and the location of the new generation can influence whether network upgrades are required by the addition of new generation. Moreover, network upgrades can range from minor additions such as a bank of capacitors to expensive undertakings such as the construction of a new transmission line. All other things being equal, utilities will try to plan their generation additions to avoid or minimize the need for network upgrades.

Additionally, in practice, when viewed from a system perspective, the addition of significant levels of non-firm QF generation onto the system consumes available transmission capacity on the grid. The resulting impact is the acceleration in need for system upgrades in order to place firm generation into service which is required to backstand non-firm QF generation. The concept of paying avoided transmission system upgrade cost to the QF generator would imply that the addition of non-firm generation on the system has deferred the need for system upgrades. However, the trend of QFs locating in areas of cheap land has not coincided with the areas of load growth, resulting in many of them becoming transmission capacity consumers instead of transmission capacity providers.

Q. WHAT WOULD BE THE CHANGE IN AVOIDED CAPACITY COSTS IF THE COMMISSION ACCEPTED SBA WITNESS BURGESS' RECOMMENDATIONS REGARDING THE USE OF AN AERO-DERIVATIVE CT AND ADDING TRANSMISSION SYSTEM UPGRADE COSTS?

A. Based on Mr. Burgess' calculations that he presents on page 60 of his Direct Testimony, the capital cost assumptions would increase the capacity cost by 104% for both DEC and DEP. Or, stated another way, Mr. Burgess' capital cost recommendations would more than double the capacity payments made by Duke's customers to solar QF providers. The resulting impact would be for consumers to pay twice as much for capacity purchased from QF generation relative to the equivalent capacity cost that would otherwise have been incurred if the capacity would have been provided by the utility. While Mr. Burgess' use of the higher capacity cost would be a good subsidy to the benefit of the QF developer, it would also violate the fundamental indifference principle of PURPA and Act 62.

Q. TURNING TO ORS CONSULTANT WITNESS HORII, DOES MR. HORII AGREE WITH THE AVOIDED CAPACITY CALCULATION FILED IN THIS PROCEEDING?

A. Not entirely. Mr. Horii does agree with the overall approach utilized by the Companies to value avoided capacity benefits within the construct of the peaker methodology. He also agrees with the majority of inputs used in the determination of the avoided cost rate calculation. For example, Witness Horii does not disagree with the use of the CT technology nor the CT costs used in the determination of the capacity rate. However, Witness Horii does take issue with two items. First, he recommends changes to the calculation of the Companies' annual fixed charge rate for both DEP and DEC. Second, for DEC, he recommends changes to the seasonal allocation of capacity.

Q. PLEASE ELABORATE ON WITNESS HORII'S CONCERN WITH THE COMPANIES' FIXED CHARGE RATE CALCULATION AS WELL AS HIS RECOMMENDATION ON THIS MATTER.

A. Witness Horii points out the importance of the "economic life" assumption for a CT in the calculation of the annual fixed charge rate. Since the fixed charge rate essentially calculates the annualized cost of the peaker including the levelized return of, and return on investment, the shorter the assumed life the higher the annual avoidable cost of the CT. Specifically, Mr. Horii takes issue with the 35-year useful life assumption incorporated by the Companies in the derivation of avoided capacity rates. He recommends using a 20-year useful life and supports that assumption pointing to other jurisdictions and studies that use a 20-year life such as California and the Lazard Levelized Cost of Energy Analysis report. He goes on to recommend increasing the fixed charge used in the calculation for DEP from 7.189% to 9.394% and for DEC from 7.635% to 9.831%. This would effectively increase the capacity cost customers pay for QF capacity by approximately 30% over the capacity rates recommended by each of the Companies.

Q. HOW DO YOU RESPOND TO MR. HORII'S CRITIQUE OF THE USEFUL ECONOMIC LIFE OF THE CT?

A. I agree with Witness Horii that other jurisdictions and other studies use varying economic life assumptions. However, the issue before this Commission as it relates to this matter is what assumption of a CT useful life does South Carolina assume for purposes of establishing cost of service based rates? Since consumers in South Carolina pay for both traditional generation and PURPA QF generation, it is reasonable that the assumption of useable economic life should be the same in either case. The PURPA indifference principle requires that consumers not pay more for capacity from QFs than they would otherwise pay for traditional capacity. Since the 35-year useful life assumption used in the development of capacity rates in this case is consistent with the Company's IRP, it is appropriate to utilize this same assumption for avoided cost purposes. .

Q. IN DEVELOPING ITS AVOIDED COST RATES, DOES DUKE INCLUDE ALL COSTS ASSOCIATED WITH OPERATING AND MAINTAINING A CT FOR A 35-YEAR USEFUL LIFE?

A. Yes. As I have discussed, the capital cost of the CT is based on publicly available EIA data and includes adjustments associated with economies of scale for constructing a four-unit greenfield site. The fixed operations and maintenance ("FOM") cost is included in the calculation of the annual capacity cost and includes labor, office and administration, training, contract labor, safety, building and ground maintenance, communication and laboratory expenses. The variable O&M cost is modeled in PROSYM and includes routine maintenance, makeup water, water treatment, water disposal, and other consumables excluding fuel. In addition, the major maintenance cost assumes third party maintenance based on the recommended maintenance schedule set forth by the original equipment manufacturer ("OEM") in order to meet the 35-year useful life of the CT. The major maintenance cost is modeled separately from VOM and is included in PROSYM as a start cost for CTs. Thus, the capital and FOM costs are included in the annual capacity cost in developing the avoided capacity rates paid to QFs, and VOM and major maintenance costs are captured in the PROSYM production cost model and reflected in the avoided energy rates.

Q. DID INTERVENORS AGREE WITH THE COMPANIES' FIRST YEAR OF NEEDS FOR PURPOSES OF CALCULATING AVOIDED CAPACITY COST?

A. ORS Witness Horii agreed with the Companies' first need determination based on his review of the 2019 IRPs.[37] SBA Witness Burgess agreed that DEC may not have a capacity need to cover internal capacity deficiencies until 2026, but suggested that DEC's customers should pay for QF capacity beginning in 2020 since the Companies could sell excess capacity either bilaterally or into the PJM market. He additionally argued that QFs provide an "option value" of capacity to the Companies beyond their initial contract term, and recommends the Commission adjust the Companies' avoided cost rates in future proceedings to reflect this "option value."

Q. DO YOU AGREE WITH SBA WITNESS BURGESS' ARGUMENT THAT UNDER PURPA, DUKE SHOULD BE OBLIGATED TO PAY QFS FOR EXCESS QF CAPACITY THAT COULD POTENTIALLY BE SOLD TO NEIGHBORING UTILITIES?

A. No. Mr. Burgess is mistaken in his assessment that the Companies should credit the QF for a capacity sale that it could potentially make to PJM. As explained below, he is incorrect first, from a legal perspective. Notwithstanding the legal issue, and as I explain further below, Mr. Burgess also selectively makes his argument without considering how his position, when adopted globally, could reduce the rates filed in this proceeding.

[37] ORS Horii Direct, at 11-12.

From a legal perspective, utilities are not obligated to pay QFs for capacity that exceeds system needs, such as for resale in a capacity market under PURPA. FERC has long held that "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity…[the purchase] obligation does not require a utility to pay for capacity that it does not need."[38] FERC has also expressly stated that "there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for the capacity."[39] More recently, in *Hydronamics,* FERC reiterated that "when the demand for capacity is zero, the cost for capacity may also be zero."[40]

As I explained in my Direct Testimony, DEC's and DEP's next avoided capacity need is not until 2026 and 2020, respectively. Accordingly, DEC and DEP should not be obligated to pay QFs for capacity—by selling excess QF capacity into a capacity market or otherwise—until those years when DEC (2026) and DEP (2020) actually have a need for capacity.

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[38] *City of Ketchikan*, 94 FERC ¶ 61,293 (2001) *("Ketchikan") citing Order No. 69, FERC Stats. & Regs., Preambles 1977-1981*, P30,128 at 30,865.
[39] *Id.*
[40] *Hydrodynamics, Inc.*, 146 FERC ¶ 61, 193, at ¶ 35 (2014).

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING SBA WITNESS BURGESS' RECOMMENDATION TO REQUIRE DUKE TO PAY QFS FOR EXCESS QF CAPACITY THAT IS NOT NEEDED?

A. Beyond the fact that PURPA does not require Duke to pay for capacity that is not needed to serve customers' energy needs, it is also noteworthy that this is another example of where Mr. Burgess selectively picks an issue and applies it only in a manner that would increase avoided cost payments for QFs, without considering how his same arguments would actually serve to reduce the overall capacity and energy rate. If Mr. Burgess believes the sale of excess capacity to external third parties is appropriate, then he should also support the use of third-party capacity purchases to lower the avoided capacity rates. For example, the Companies use the full "new build" cost of a simple cycle peaking resource in the determination of its capacity rates. Following Mr. Burgess' argument, the Companies should also consider the ability to purchase wholesale capacity at or below "new build" CT costs in the determination of avoided capacity rates. Furthermore, to the extent the Companies can lower their marginal energy rates through economic purchases from the wholesale energy market, those reductions in the avoided energy rates should also be included. In summary, and for the sake of clarity, the Companies did not reduce their avoided capacity rates nor their avoided energy rates based on the potential for economic wholesale purchases, and for the same reasons, it would not be appropriate to increase avoided cost rates based on the potential for wholesale sales as suggested by Mr. Burgess.

Q. IS SBA WITNESS BURGESS' ARGUMENT THAT EXISTING QFS SHOULD BE PRESUMED TO CONTINUE TO DELIVER CAPACITY AFTER 2029 REASONABLE?

A. No. It is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally enforceable commitment guaranteeing delivery exists. QF owners have unfettered rights to make a business decision at the time their current PPA expires whether or not to establish a new legally enforceable obligation ("LEO") and contractually commit to deliver their full output, including capacity, to the utility, whether to cease operations after their current contract expires, or whether to otherwise use their facility in any lawful manner they so desire, based on the current economic, regulatory, and market circumstances existing at the time their current PPA expires.

Additionally, the Companies and their customers have no guarantee that the contracted facility will be physically capable of providing energy and capacity beyond the contract period. The facility may have degraded mechanically, may have lost its land lease or may lack the operations and maintenance funding to run beyond the contracted period.

Duke's current and consistent position across numerous biennial IRP planning cycles has been to treat all wholesale purchase contracts the same and to recognize that a QF's legally enforceable commitment to provide energy and capacity extends only for the duration of its PPA. Duke's position is also fully consistent with FERC's implementing regulations, which provide QFs the right to establish a legally enforceable obligation committing to "the delivery of energy or capacity over a specified term . . ."[41] Thus, it clearly seems inconsistent with PURPA to presume that a commitment made for a specified contact term somehow obligates the QF to continue to deliver power to the utility after its contract term ends.

Q. DO YOU BELIEVE SBA WITNESS BURGESS' PROPOSAL TO ASSUME QFS WILL RENEW THEIR CONTRACTS AND CONTINUE DELIVERING CAPACITY AFTER THEIR INITIAL CONTRACT TERM IS DISCRIMINATORY AND IN VIOLATION OF PURPA?

A. Yes. Importantly, again, Mr. Burgess' proposal is clearly intended to advantage existing QFs over a new QF or other capacity resource, and therefore is discriminatory towards other traditional and non-traditional utility resources. Duke is obligated to treat all existing and renewing QFs in a non-discriminatory fashion. Upon any QF making a new legally enforceable commitment to sell its output, Duke is then obligated to purchase the QF's output at its current avoided costs fixed at the time a LEO is established for the term of the contract.

Q. SHOULD THE COMPANIES' AVOIDED CAPACITY RATES BE APPROVED BY THE COMMISSION?

A. Yes. The Companies have fairly and accurately calculated the avoided capacity rates applicable to QFs eligible for the standard offer tariff.

[41] 18 C.F.R. 292.304(d)(2).

b. <u>Seasonal Allocation</u>

i. <u>Response to ORS Witness Horii</u>

Q. WHAT WAS THE BASIS FOR THE COMPANIES' SEASONAL CAPACITY ALLOCATION AND DEFINITION OF CAPACITY PAYMENT HOURS?

A. The Companies relied upon the Solar Capacity Value study conducted by Astrapé Consulting in 2018. The study examined the impacts of varying levels of solar on DEC's and DEP's system and showed that as the level of solar penetration increases on the system, the allocation of capacity value shifts increasingly toward the winter. In technical terms, the study demonstrated that solar resources contribute, in part, to reductions of summer loss of load expectation ("LOLE") risk but have very little impact on winter LOLE since winter peaks occur in non-daylight hours. Hence the winter/summer allocation factor is influenced by the amount of solar assumed to be on the system. Specifically, Duke used the "Tranche 4" level of solar identified in the study to determine the seasonal allocation factors used in this case.

Q. CAN YOU EXPAND FURTHER ON WHY THE ADDITION OF SOLAR RESOURCES RESULTS IN A SHIFT OF LOSS OF LOAD RISK FROM THE SUMMER TO THE WINTER?

A. When assessing loss of load risk, it is helpful to think of the Companies serving load net of must-take solar output. In the winter, peak loads for DEC and DEP occur in the early morning and evening hours when the solar output is very low, while peak loads in the summer occur across the afternoon and early evening which is more coincident with solar output. Thus, solar resources effectively reduce load (and corresponding loss of load risk) in the summer, but do little to help the Companies meet winter peak demands which results in a shift of loss of load risk to the winter period.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY TRANCHE 4 LEVEL OF SOLAR RESOURCES.

A. North Carolina Session Law 2017-192, House Bill 589 ("N.C. HB 589") established the Competitive Procurement of Renewable Energy ("CPRE") Program competitive solicitation process, which calls for the addition of 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period. The total CPRE target of 2,660 MW via annual competitive solicitations will vary based on the amount of "Transition" MW at the end of the 45-month period, which N.C. HB 589 expected to total 3,500 MW. If the aggregate capacity of the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount. N.C. HB 589 also allows for up to 600 MW of renewable energy procurement programs for large customers such as military installations and universities, as well as a community solar program.

At the time that the Solar Capacity Value study was being conducted, the Companies' projection of total solar mandated by N.C. HB 589 and solar included in SC Act 236 corresponded to the "Tranche 4" level of solar in the study, which reflected 3,500 MW of cumulative solar for DEC and 3,585 MW for DEP. While the exact timing and amounts of transition and incremental solar additions may change over time, the Companies believe that it is reasonable to assume the cumulative mandated levels of solar under Tranche 4 for purposes of calculating the standard offer avoided cost rates.

Q. WHAT IS THE STATUS OF THE COMPANIES' CPRE SOLICITATION?

A. On July 10, 2018, Duke issued a request for bids for the first Tranche of CPRE, requesting 600 MW in DEC and 80 MW in DEP. Of the total number of projects selected by the independent administrator, a total of 13 projects signed PPAs. Ten of the projects will be located in North Carolina and three projects will be located in South Carolina. As explained by Duke Witness George Brown, the Companies plan to issue a request for bids for the second Tranche of CPRE (680 MW) in October 2019.

Q. BEYOND THE CURRENT COMPETITIVE SOLICITATION ACTIVITIES, ARE THE ADDITIONAL VOLUMES REQUIRED TO ACHIEVE THE TRANCHE 4 LEVEL OF SOLAR RESOURCES OPTIONAL?

A. No. The Tranche 4 level of solar resources is mandated through existing legislation under N.C. HB 589 and the Companies also assumed the SC Act 236 solar additions as well when determining the total projected "Tranche 4" level of solar.

Q. WHAT DO THE TRANCHE 4 RESULTS SHOW REGARDING LOSS OF LOAD RISK?

A. As presented in detail in the Solar Capacity Value Study as described in the Companies' 2018 IRPs, 100% of DEP's loss of load risk occurs in the winter and approximately 90% of DEC's loss of load risk occurs in the winter.[42] Thus, DEP's filed rates in this proceeding pay all of its annual capacity value in the winter while DEC's new rates pay 90% of its annual capacity value in the winter and the remaining 10% in the summer period.

Q. DOES ORS WITNESS HORII SUPPORT SEASONAL ALLOCATION METHODOLOGY RELYING UPON FUTURE LOSS OF LOAD EXPECTATION (LOLE) DATA FOR DETERMINING THE ALLOCATION OF CAPACITY COSTS?

A. Yes. On page 14 of Mr. Horii's Direct Testimony he states, "DEC correctly allocates the capacity costs based on the relative Loss of Load Expectation ("LOLE") in each time period."

Q. ON PAGE 16 OF HIS DIRECT TESTIMONY, MR. HORII RECOMMENDS USING THE LOLE DATA FROM THE "EXISTING PLUS TRANSITION" CASE, RATHER THAN THE TRANCHE 4 CASE, TO DETERMINE THE SEASONAL ALLOCATION AND DEFINITION OF CAPACITY PAYMENT HOURS. DO YOU AGREE WITH THAT RECOMMENDATION?

A. No, I do not. Given that Tranche 4 level of solar resources is mandated by existing legislation, I believe that solar procured under the Standard Offer rates in this docket should be priced as incremental to the Tranche 4 level of solar. Pricing solar

[42] *See* DEC 2018 IRP, Chapter 9 (Capacity Value of Solar), at 40-41; DEP 2018 IRP, Chapter 9 (Capacity Value of Solar), at 40-41.

based on lower Existing plus Transition solar would essentially result in double counting and overpayment for QF solar by Duke's customers.

Q. WHAT SEASONAL CAPACITY ALLOCATION DOES MR. HORII RECOMMEND AND WHAT IS HIS BASIS?

A. Based on a starting assumption of less solar on the system, Mr. Horii recommends a 60% winter/40% summer weighting for DEC and 99% winter/1% summer weighting for DEP. He appears to discount the regulatory mandate to procure solar up to the Tranche 4 levels of solar and only considers the "existing plus transition level of solar" when recommending a more summer oriented allocation of capacity for DEC. Since DEP is a more winter peaking utility, and DEP already has an extensive penetration of solar on the system, Mr. Horii and the Companies essentially agree that all capacity value for DEP is already in the winter. I believe the 99% winter allocation for DEP as recommended by Mr. Horii and the 100% allocation used by the Companies are essentially the same when rounded to a level of significance.

Q. FOR DEC, HOW MUCH SOLAR CAPACITY IS UNDER CONTRACT OR COMMITTED THROUGH TRANCHE 1 THAT WOULD LIKELY BE ONLINE PRIOR TO OR IN THE SAME TIMEFRAME AS QF SOLAR ADDED UNDER THIS DOCKET?

A. After taking into consideration the fully contracted MW acquired in CPRE Tranche 1, the estimate of existing and fully contracted solar for DEC is approximately 1,400 MW. This level is expected to rise as current contracts under negotiation are executed.

Q. EVEN IF ONE WERE TO ACCEPT ORS WITNESS HORII'S PREMISE THAT FUTURE REGULATORY MANDATED SOLAR SHOULD NOT BE CONSIDERED IN DETERMINING THE SEASONAL ALLOCATION, WHAT IS THE CORRECT SEASONAL WEIGHTING BASED ON EXISTING AND CONTRACTED LEVELS OF SOLAR RESOURCES?

A. The current DEC estimate of installed and contractually obligated solar would yield a seasonal allocation of approximately 80% winter and 20% summer based on the Solar Capacity Value study results. These weightings demonstrate how quickly loss of load risk shifts to the winter as greater and greater amounts of solar are added to the system. Witness Horii, when making his recommendation, did not appear to have information on the amount of additional solar that has already been fully contracted through CPRE. As I just explained, when adjusting for this information, even if one were to use Witness Horii's allocation methodology it would be appropriate to adjust the DEC seasonal allocation to 80% winter and 20% summer.

Q. NOTWITHSTANDING WITNESS HORII'S RECOMMENDATION ON THIS ISSUE, DO YOU STILL BELIEVE THAT THE TRANCHE 4 LEVEL OF SOLAR ASSUMPTION IS FAIR TO THE COMPANIES' CUSTOMERS AND QFs?

A. Yes. The Tranche 4 level of solar resources is required by legislation and will be procured over the next few years. Basing the seasonal allocation on anything less than Tranche 4 would result in double counting and overpayment of solar QF capacity by Duke's customers.

ii. Response to SBA Witness Burgess

Q. DID SBA WITNESS BURGESS IDENTIFY CONCERNS WITH DUKE'S SEASONAL CAPACITY ALLOCATION?

A. Yes. SBA Witness Burgess believes that the seasonal allocation modeled by Duke may be incorrect and biased against solar QFs.[43]

Q. DO YOU AGREE WITH MR. BURGESS' ASSESSMENT?

A. No, I do not. SBA Witness Burgess' comments and recommendations regarding the seasonal capacity allocation are consistent with the theme throughout his Direct Testimony that avoided cost rates should focus on benefitting solar QFs, rather than ensuring that customers remain indifferent to QF purchases. Specifically, Mr. Burgess argues:[44]

> Since very little solar energy is available during the Duke defined wintertime periods, higher winter allocation factors (and correspondingly lower summer factors) will lead to lower overall revenues for solar QFs. For example, I estimate that shifting just 10% of the capacity allocation from the Winter A.M. period to the Summer P.M. period for DEC would increase solar QF capacity revenues by over 50%. A similar 10% shift for DEP would increase solar QF capacity revenues by 115%. As such, the allocation factors have an outsized impact on the ability for QFs to obtain fair compensation in exchange for the capacity value they provide.

Q. PLEASE RESPOND TO SBA WITNESS BURGESS' STATEMENT.

A. Although I have not analyzed Mr. Burgess' math, a shift in capacity payment hours from Winter AM to Summer PM would unfairly benefit solar QFs at the expense of the Companies' customers and is in violation of PURPA's indifference principle. The problem with Mr. Burgess' statements is that the Companies' need for capacity

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[43] SBA Burgess Direct, at 46.
[44] SBA Burgess Direct, at 45-46.

is primarily in the winter. Recognizing this, the capacity payment hours were developed to incent QFs to provide power when customers need it the most, which may (or may not) align with and when QFs provide power to the system.

Q. HOW DOES MR. BURGESS ATTEMPT TO ARGUE IN SUPPORT OF HIS POSITION?

A. Mr. Burgess criticizes some of the assumptions in the Solar Capacity Value Study including the underlying load forecasts, differences in the availability of demand response in winter and summer months, and characterization of neighboring utility capacity support. Mr. Burgess also lists seasonal variations in assumptions for forced outage rates and planned maintenance as a biased assumption, but fails to expand on his concerns with that issue.[45]

Q. PLEASE EXPLAIN DUKE'S POSITION REGARDING THE LOAD FORECAST CLAIMS.

A. Regarding the load forecast, Mr. Burgess correctly explains, and as I mentioned previously, that the seasonal allocations were based upon results from the Solar Capacity Value study. The study was based on study year 2020 and thus included the 2020 forecast for load and energy. Mr. Burgess suggests that load growth and load shapes may shift over time and may shift the allocation back toward summer hours. The Companies note that while this may potentially be the case, the Companies' best estimate of the value of incremental QF solar capacity is reflected and validated by the study's results. To the extent the load growth and load shapes shift over time, such changes will be incorporated in future studies and reflected in

[45] SBA Burgess Direct, at 47-48.

future rate designs. It would neither be practical nor reasonable to accept Mr. Burgess' arbitrary assumptions of potential future changes to seasonal capacity needs in order to benefit solar QFs. Such an approach would not send the right price signals to QFs regarding the timing and need for QF capacity and energy.

Q. WHAT IS MR. BURGESS' CONCERN REGARDING THE COMPANIES' DEMAND RESPONSE PROGRAMS?

A. Mr. Burgess criticizes the Companies' demand response assumptions which show greater demand response capability in the summer as compared to the winter. SACE/CCL Witness Wilson expresses similar concerns.

Mr. Burgess requested a revised study that assumed winter demand response was somehow increased to the same level as summer demand response. The Companies did not run this scenario since it is irrelevant given that large quantities of demand response participation are not achievable within such a short timeframe nor are they appropriate to assume in this case.

To explain further, Duke's actual program experience from DEP EnergyWise Home has shown that winter residential demand response program "potential" is more difficult to achieve than summer potential for several reasons. First, not all residential customers have electric resistance hot water heaters or heat pumps with electric resistance strip heat. Instead, almost all have compressorized cooling in the form of straight air conditioning or heat pumps. Second, residential winter measure installations require appointments to enter the customer's home that are often rescheduled and more costly than a summer air conditioning installation, which does not require an in-home installation. While it is fair that greater winter demand response capability would help mitigate winter peak demands, the planned demand response potential that is reasonably achievable must be based on Duke's experience with program adoption and, in Duke's experience, adoption of high levels demand response programs has been challenging despite significant efforts by the Companies. Finally, it would only be appropriate to consider this potential outcome, if at some future point the Companies' experience suggests additional winter demand response is possible and such results were included in future winter DSM forecasts. It is not appropriate to pre-assume that outcome, or its impact on avoided cost rates at this point in time.

Q. WHAT CONCERN DOES SBA WITNESS BURGESS EXPRESS REGARDING NEIGHBOR ASSISTANCE?

A. Mr. Burgess also states that DEP and DEC are neighbors to several summer peaking utilities that may have available resources to contribute to winter peaking needs. Mr. Burgess also suggests that greater summer capacity allocation may be artificially limited in Duke's modeling due to assumed transmission constraints.

Q. ARE THE NEIGHBOR ASSISTANCE CRITICISMS RAISED BY MR. BURGESS ACCURATE?

A. No, they are not. The Astrapé Solar Capacity Value study modeled the DEC and DEP systems with interconnections to neighboring utilities which allow the Companies to carry lower reserve margins than otherwise would be needed as a result of the diversity in load and forced outages across the interconnected system. The Astrapé studies included comprehensive modeling of the load, resources and transmission capability of neighboring utilities. The studies showed that even during times of extreme peak demands, the SERVM[46] model showed that significant purchases were available from neighboring utilities. Thus, contrary to Mr. Burgess' concerns, the Companies and Astrapé had previously identified that the robustness of the power market assumed in the studies may have actually been somewhat overstated (i.e., lead to the adoption of a lower reserve margin). The Companies plan to update the resource adequacy studies including market assistance modeling in support of their 2020 IRPs.

Q. DID SBA WITNESS BURGESS EXPRESS ANY OTHER CONCERNS WITH THE COMPANIES' SEASONAL CAPACITY ALLOCATION?

A. Yes. Mr. Burgess tried to make the case that the seasonal allocations do not make sense based on a review of historical load data for DEC and DEP. SACE/CCL Witness Wilson made a similar argument.[47]

Q. PLEASE DESCRIBE THE ANALYSIS CONDUCTED BY SBA WITNESS BURGESS.

A. Mr. Burgess apparently used the 1980-2015 load shapes developed by Astrapé from the Solar Capacity Value study to analyze summer versus winter loads. However, it is unclear from his Direct Testimony exactly how he used the data. I requested Mr. Burgess' supporting data and calculations in DEC_DEP RFP 1-10 but have not received a response as of the filing of my Rebuttal Testimony.

Mr. Burgess states on page 51 of his Direct Testimony that, "[o]f the top 5% of load hours during this historical period (i.e. the 95th percentile), the vast

[46] Strategic Energy and Risk Valuation Model (SERVM) is Astrapé Consulting's proprietary reliability planning software model.
[47] SACE/CCL Wilson Direct, at Exhibit B, at 22.

majority occurred during the summer months (July and August) rather than winter months (December, January, and February)." However, it is unclear what Mr. Burgess means by the "top 5% of load hours." Regardless, based on Mr. Burgess' analysis, he concludes that the "vast majority" of high load hours occurred during the summer months and thus the Companies' proposed allocations do not make sense.

Q. ARE THERE ANY FLAWS WITH SBA WITNESS BURGESS' LOAD ANALYSIS?

A. Yes. Regardless of the exact methodology employed by Mr. Burgess, my primary concerns are that Mr. Burgess apparently did not take into account the impact of must-take solar output in his analysis and he also incorrectly included an extremely broad number of hours by using the "top 5% of load hours."

Q. WHY SHOULD MUST-TAKE SOLAR OUTPUT BE CONSIDERED WHEN CORRELATING HISTORIC LOAD DATA TO LOLE AND SEASONAL CAPACITY ALLOCATION?

A. SBA Witness Burgess and SACE/CCL Witness Wilson point out that DEC and DEP experience significant summer demands. However, as previously discussed, summer peaks occur in late afternoon hours when solar has significantly greater energy contributions as compared to dark winter mornings where very little—if any—solar is available at the time of peak. Thus, in the summer peak, loads net of solar output are reduced relative to winter peak loads net of solar. With the significant penetration of solar resources in recent years, the Companies no longer serve load, but rather serve load net of must-take solar output. It is the load net of solar that has an impact on summer versus winter reserves and LOLE values, and represents the actual net load that the remainder of the Companies' resources must satisfy. SBA Witness Burgess appears to completely ignore this fact in his analysis.

Q. YOU MENTIONED THAT SBA WITNESS BURGESS UTILIZED AN OVERLY BROAD NUMBER OF HOURS IN HIS ANALYSIS. PLEASE EXPLAIN YOUR CONCERN.

A. As previously noted, Mr. Burgess' analysis was based on the "top 5% of load hours." Beyond the error I previously mentioned with respect to his exclusion of must take solar output, this broad range of hours is far in excess of the number of hours that would have statistically relevant value in the context of an LOLE analysis.

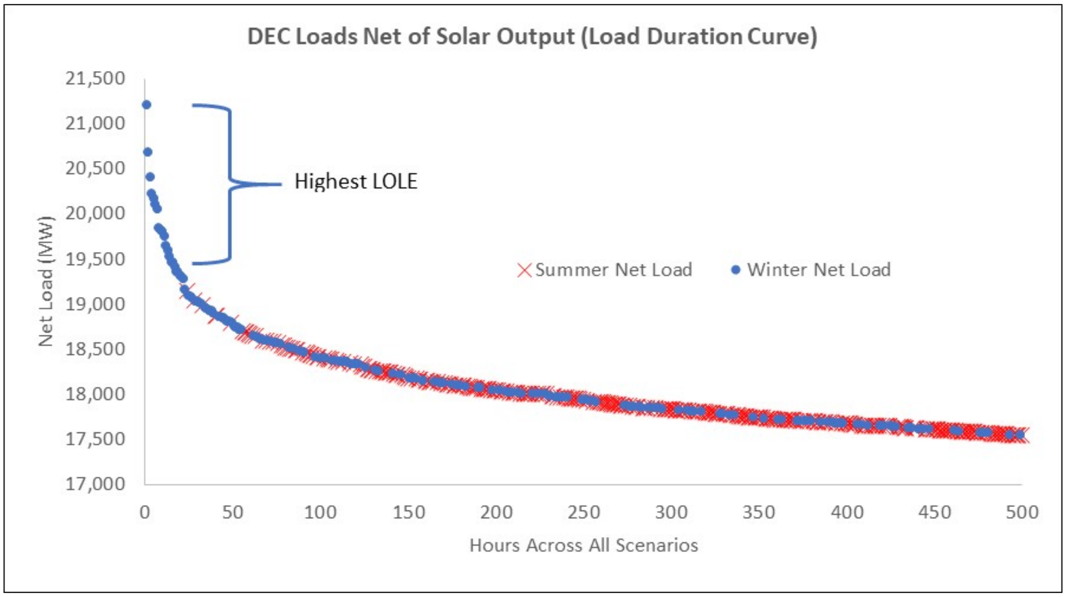
Q. PLEASE ELABORATE ON WHY THE NUMBER OF HOURS BEING EVALUATED IS IMPORTANT.

A. Most reliability events are high impact, low probability events, and thus a large number of load, unit outage and forecast uncertainty scenarios must be considered. The tails of the resulting reliability distribution reflect high load events and may be coupled with greater levels of unit outages and forecast uncertainty. These scenarios drive the LOLE results as opposed to scenarios where weather is less extreme and units perform well. Thus, statistically significant levels of LOLE only occur in a very limited number of hours of the year and not in 5% of the hours of the year, which represents 438 hours in a year. Therefore, many of the hours included in the broad range defined by Mr. Burgess have no statistical significance for purposes of determining LOLE or the resulting seasonal allocation. While the finer details of Mr. Burgess' calculations are unclear, it is clear that he inappropriately used an overly broad range of historic load hours to arrive at his seasonal allocation conclusions. This large block of hours represents energy value which the QF is being compensated for under the Companies' rate design, but does not represent capacity value.

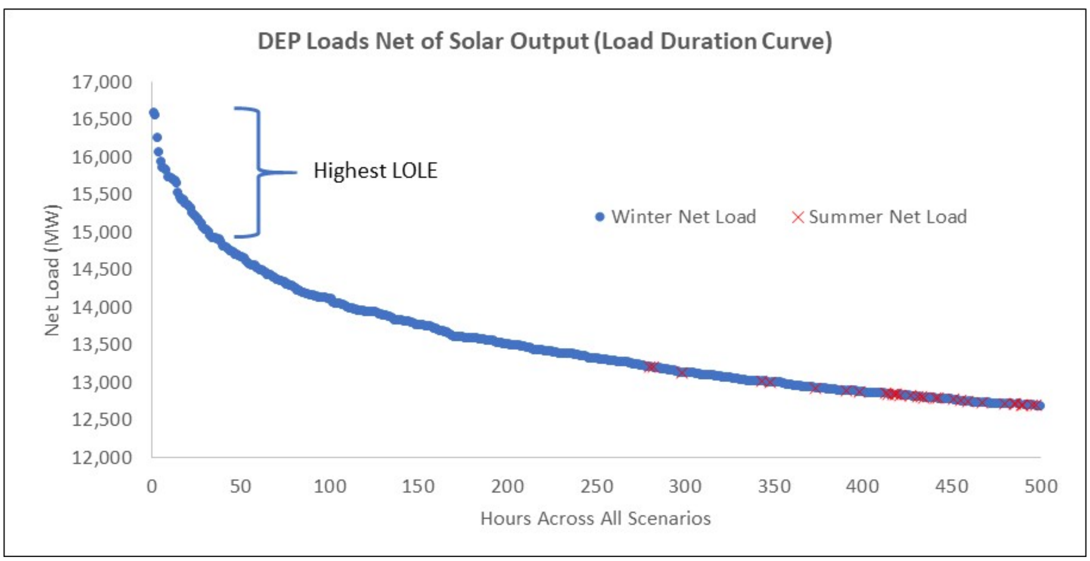
Q. PLEASE PROVIDE ADDITIONAL PERSPECTIVE REGARDING HOW HISTORIC LOAD DATA RELATES TO LOLE AND THE COMPANIES' SEASONAL ALLOCATION VALUES.

A. The Companies used the same data source for historic loads as used by Mr. Burgess, except that the Companies appropriately analyzed load net of must-take solar resources and also developed the data in load duration curve ("LDC") format. A load duration curve is similar to a load curve but the demand data is ordered in descending order of magnitude, rather than chronologically. The results of the analysis are provided in the figure below. Again, the majority of reliability events are high impact, low probability events and LOLE occurs in a limited number of hours typically reflecting the highest load hours net of solar output. As denoted by the brackets in the Figures 5 and 6 below, there are significantly higher winter load hours net of solar output for both DEC and DEP compared to summer load hours net of solar output. These high winter net load hours are the hours when the majority of the LOLE contribution occurs, and the number of hours with statistically significant levels of LOLE are far less than the 5% of load hours presented by Mr. Burgess. The analyses presented by Mr. Burgess, and similarly by Mr. Wilson, may be interesting academic exercises but do not support a different seasonal allocation as Mr. Burgess and Mr. Wilson have suggested.

<u>Figure 5</u>



<u>Figure 6</u>



Q. DO YOU HAVE ANY OTHER COMMENTS RELATED TO SACE/CCL WITNESS WILSON'S AND SBA WITNESS BURGESS' CRITICISMS OF SEASONAL ALLOCATION?

A. Yes. I would note that the Companies asked Mr. Burgess in a data request why his analysis did not consider the impact of must-take solar output; however, the Companies have not received a response to this question. SACE/CCL Witness Wilson also presented the same historic load analysis in this proceeding as he presented in NCUC Docket No. E-100, Sub 157. In the North Carolina docket, Duke asked whether Mr. Wilson's analysis of seasonal weighting reflected consideration of load net of solar resources. SACE et al. responded, "…that comment referred to load, not load net of any particular resources."[48] Further, when asked to provide a detailed explanation of why Mr. Wilson believes it is appropriate to exclude the impact of must-take solar generation when evaluating seasonal loss of load risk, Mr. Wilson's representative organization responded, "Not applicable." Clearly Mr. Burgess and Mr. Wilson have made the same errors in their analysis which invalidate any conclusions they attempt to make.

iii. Response to SACE/CCL Witness Wilson

Q. PLEASE DESCRIBE SACE/CCL WITNESS WILSON'S TESTIMONY REGARDING THE COMPANIES' SEASONAL CAPACITY ALLOCATION.

A. SACE/CCL Witness Wilson filed Direct Testimony in this docket that relied almost exclusively upon his past assessment of the Companies' 2016 Resource Adequacy

[48] SACE et al. Response to Duke Data Request 4-5, NCUC Docket No. E-100, Sub 157.

studies and the 2018 Solar Capacity Value study conducted by Astrapé (included as Exhibit B to Mr. Wilson's Direct Testimony). Mr. Wilson's criticisms were largely the same as comments that SACE filed in NCUC Docket No. E-100, Sub 147 (2016 IRP), comments filed in NCUC Docket No. E-100, Sub 157 (2018 IRP) and testimony filed in NCUC Docket No. E-100, Sub 158 (2018 Avoided Cost).

Q. PLEASE BRIEFLY DESCRIBE THE ASTRAPÉ STUDY METHODOLOGY.

A. As I previously noted, most reliability events are high impact, low probability events, and thus a large number of scenarios must be considered. Astrapé utilized the SERVM reliability model to perform over 3,600 yearly simulations at various reserve margin levels. Each of the 3,600 yearly simulations was developed through stochastic modeling of the uncertainty of weather, economic growth, unit availability, and transmission availability. Astrapé used weather data dating back to 1980 to capture potential load uncertainty due to extreme weather.

Q. WHAT CRITICISMS WERE IDENTIFIED BY SACE/CCL WITNESS WILSON?

A. Mr. Wilson identified his concerns with the methodology used by Astrapé to capture the relationship between load and cold weather, economic load forecast uncertainty modeling and operating reserve assumptions. As I previously mentioned and addressed, Mr. Wilson also criticized the Companies' demand response assumptions.

Q. HAVE YOU WORKED TO RESOLVE ANY OF THE CONCERNS IDENTIFIED BY SACE/CCL WITNESS WILSON?

A. Yes. Since 2016, the Companies have responded to numerous data requests across multiple dockets, and conducted additional sensitivities and scenarios requested by the NC Public Staff in efforts to help interested parties, including Mr. Wilson, understand the finer details of the study methodology and assumptions. In addition, the NCUC directed the Companies to work with the NC Public Staff to address outstanding concerns raised by the Public Staff and Mr. Wilson regarding the 2016 Resource Adequacy studies.[49] The NCUC further directed the Companies and the NC Public Staff to file a Joint Report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP updates.

The Companies and Astrapé worked with the NC Public Staff in efforts to resolve outstanding concerns related to the 2016 Resource Adequacy studies and filed the Joint Report on April 2, 2018. The discussions with the NC Public Staff were helpful and the parties were able to reach agreement on most issues.

Q. DID YOU RESOLVE THE CONCERNS RELATED TO THE CORRELATION OF LOAD AND EXTREME COLD TEMPERATURES WITH THE NC PUBLIC STAFF?

A. Yes. Load uncertainty due to extreme temperatures is a significant driver of LOLE and can be challenging to capture since there are few instances in recent history to correlate load with extreme temperatures. Based on results of some additional

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[49] NCUC's June 27, 2017 Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans in Docket No. E-100, Sub 147, at 22-23.

sensitivities requested by the NC Public Staff, the NC Public Staff was satisfied that the approach taken to capture the correlation of load and extreme weather was reasonable.[50]

Q. WHAT WAS SACE/CCL WITNESS WILSON'S CONCERN REGARDING THE OPERATING RESERVES ASSUMPTION?

A. Mr. Wilson claims that the modeling assumption used in the resource adequacy study held back over 1,000 MW of operating reserves for DEC and about 750 MW for DEP causing firm load to be shed during brief winter morning load spikes.[51]

Q. IS MR. WILSON CORRECT IN HIS ASSERTION?

A. No.

Q. HAVE YOU PREVIOUSLY DEMONSTRATED THAT SACE/CCL WITNESS WILSON'S ASSERTION IS INCORRECT?

A. Yes. SERVM allows operating reserves to drop to the regulation requirement which was 216 MW in DEC and 134 MW in DEP prior to shedding load. The Companies provided this information to SACE and Mr. Wilson in response to DEC-DEP SACE Data Request 2-19 in NCUC Docket No. E-100, Sub 147. This item was also addressed in the Companies' reply comments filed in NCUC Docket No. E-100, Sub 157. Yet, Mr. Wilson continues to make the same, unsubstantiated claims regarding the operating reserves policy used in the studies. Mr. Wilson's arguments have no basis in fact and should be rejected.

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[50] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at 2.
[51] SACE/CCL Wilson Direct, Exhibit B, at 20-21.

Q. PLEASE EXPLAIN THE ECONOMIC LOAD FORECAST UNCERTAINTY ISSUE.

A. The Astrapé studies include methodology to capture economic load growth uncertainty since a change in the underlying economic assumptions can impact the peak demands forecasted years in advance. Mr. Wilson criticized this aspect of the Astrapé study and believes that the resulting reserve margin is overstated.

Q. WOULD THIS ISSUE HAVE ANY IMPACT ON THE COMPANIES' RATE DESIGN OR SEASONAL CAPACITY ALLOCATION IN THIS PROCEEDING?

A. No, it would not. Adopting Mr. Wilson's recommendations would only serve to lower the reserve margin requirement but would not have any impact on the allocation of LOLE or the Companies' rate design. If anything, a lower reserve margin could push out the date of the first capacity need for each utility, an outcome that would increase reliability risk and reduce capacity payments for QFs.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING SACE/CCL WITNESS WILSON'S TESTIMONY?

A. Yes. Mr. Wilson's Exhibit B correctly notes that the particular season, months and hours when loss of load risk occurs is sensitive to many input assumptions that can change over time including load shapes, demand response, and solar and wind penetration. I also agree with Mr. Wilson that the price signals inherent in the rate design can shift capacity needs to adjacent hours or months.[52] However, I do not agree with Mr. Wilson's conclusion that the Companies should strive for price

[52] SACE/CCL Wilson Direct, Exhibit B, at 24.

signals that are likely to remain reasonably stable as conditions change. The Companies' filed rate design is intended to provide accurate price signals for the value of the next increment of QF capacity. The Companies anticipate that as more solar capacity is added and other conditions change, the optimal rate design may also change, which supports the avoided cost rate design being reviewed on a biennial basis.

To the extent that QF capacity added in the hours that it is most needed results in a shift of the capacity need to different hours, then the price signals included in the rate design worked as intended. As noted by ORS Witness Horii, the incremental value the QF provides is a function of the timeframe when the resource is installed.[53] Thus, the QF capacity that was procured will continue to provide value by having shifted the need to other hours, and subsequent rate designs will identify the optimal rate design for future QF additions.

Q. DOES MR. WILSON RECOMMEND ANY SPECIFIC SEASONAL WEIGHTINGS, RATE STRUCTURES OR RESERVE MARGINS?

A. No, he does not. Mr. Wilson only recommends that the proposed monthly and hourly rates structures be rejected.[54]

Q. DO YOU HAVE ANY FINAL COMMENTS ABOUT SEASONAL ALLOCATION OF CAPACITY BEFORE THE NCUC?

A. I would just briefly note that Witnesses in the proceeding failed to note that the NC Public Staff supports Duke's seasonal allocation of capacity value and, in fact,

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[53] ORS Horii Direct, at 15.
[54] SACE/CCL Wilson Direct, Exhibit B, at 24.

agreed to the Companies' entire avoided capacity and energy rate design in a Stipulation filed in NCUC Docket No. E-100 Sub 158 on April 18, 2019. The rate design in the North Carolina stipulation and proposed in South Carolina was in response to the input of the NC Public Staff, a consumer advocate, after they completed an extensive review of the same technical issues discussed in this case. While the views of a consumer advocate in another jurisdiction may not be determinative in this proceeding it is worth noting their alignment on these issues.

V. ANCILLARY SERVICES COSTS

a. Quantification and Implementation of SISC

Q. PLEASE REINTRODUCE THE PURPOSE OF THE COMPANIES' SOLAR INTEGRATION SERVICES CHARGE ("SISC").

A. The purpose of the SISC is to quantify and recoup the increased costs the Companies are incurring due to the injection of uncontrollable power from intermittent solar QFs onto the Companies' electric grid. As Duke Witness Holeman explains in detail, the intermittent and non-dispatchable nature of solar QFs results in additional system costs to integrate these unscheduled and unconstrained energy injections into the DEC and DEP Balancing Authorities. By establishing the SISC, the Companies account for these increased operational costs driven by the integration of intermittent solar resources, and properly allocate the costs to the cost causer—*i.e.*, the intermittent solar QF—as opposed to unfairly burdening customers with increased costs that would additionally violate the ratepayer indifference objective underlying PURPA.

Q. DO THE INTERVENING PARTIES GENERALLY CONCEDE THAT INTEGRATING INCREASED AMOUNTS OF INTERMITTENT SOLAR RESOURCES CAUSES DUKE TO INCUR INCREASED ANCILLARY SERVICES COSTS?

A. Yes. There is no dispute amongst the expert Witnesses that the integration of uncontrolled, intermittent and variable solar QFs is causing the Companies to incur increased ancillary services cost. ORS Witness Horii testifies that "it is appropriate to recognize [that] the Companies will incur additional integration costs [in] association with integrating large amounts of solar generation onto the Companies' grid."[55] Similarly, although SACE/CCL Witness Kirby critiques the Companies' Solar Ancillary Services Study ("Study") used to quantify the SISC, he agrees with the underlying premise of the Study and ultimately recommends that a reduced integration services charge be established, stating that "adding variable renewable generation to the power system may increase operating costs."[56] SBA Witness Burgess also does not dispute that integrating increased amounts of intermittent solar generation can cause increased ancillary services cost, and instead focuses his argument on the "magnitude" of integration costs projected by the Companies.[57]

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[55] ORS Horii Direct, at 23**.**
[56] SACE/CCL Kirby Direct, at 5.
[57] SBA Burgess, at 70-71.

Q. DOES THE ORS AGREE THAT THE ANCILLARY SERVICES STUDY IS AN ACCEPTABLE APPROACH TO ESTIMATING THE COMPANIES' SOLAR INTEGRATION COSTS?

A. Yes. ORS Witness Horii does not raise any concerns with the Study's premise, methodology, or results, and recommends that the Commission approve the Companies' solar integration services charge as proposed. Witness Horii additionally utilizes the Study as a benchmarking tool in Docket No 2019-184-E to evaluate the appropriateness of Dominion Energy South Carolina's integration study. Notably, as highlighted by Duke Witness Wintermantel, the NC Public Staff also supported the Study and entered into a Stipulation[58] with the Companies recommending the NCUC approve the solar integration services charge. As discussed in more detail by Duke Witness Wintermantel, the NC Public Staff also required Astrapé to run sensitivities of the Study and validated the Study against seven (7) other integration studies utilized in various U.S. jurisdictions.

Despite the SISC being supported by the ORS, and additionally validated and supported by the NC Public Staff in North Carolina, SACE/CCL Witness Kirby and SBA Witness Burgess both argue on behalf of the solar industry that the Study's quantification of the SISC is flawed and that the SISC is inappropriate. However, as discussed by Duke Witness Wintermantel, these concerns should be dismissed and the Commission should find that the Study accurately and

[58] Stipulation of Partial Settlement Regarding Solar Integration Services Charge, NCUC Docket No. E-100, Sub 158 (May 21, 2019).

appropriately quantifies the Companies' increased ancillary services costs to integrate increased amounts of intermittent solar generation.

Q. IS IT FAIR TO CHARACTERIZE THE CRITICISMS REGARDING THE QUANTIFICATION OF THE SISC RAISED BY SACE/CCL AND THE SBA AS ARGUMENTS FOR A LOWER COST INTEGRATION SERVICES CHARGE?

A. Yes. As I have stated throughout my Rebuttal Testimony, the arguments raised against the Companies' avoided cost rates by intervenors on behalf of the solar QF industry advocate for higher avoided cost rates to the benefit of the QF. Similarly, each criticism raised by SACE/CCL and the SBA regarding the quantification of the SISC ultimately argues that the Ancillary Services Study results are too high in terms of costs imposed by solar generators on the DEC and DEP systems, and that, correspondingly, the SISC should be lowered to reduce the costs assigned to solar QFs.

Q. DID THE COMPANIES BALANCE BOTH THE CUSTOMERS' AND THE QFS' INTERESTS IN PROPOSING THE SISC?

A. Yes. This is not something that I addressed in my Direct Testimony, but think it is important to bring to the Commission's attention in light of the opposition to the SISC put forward by the solar industry in this proceeding. Specifically, I want to highlight the Companies' intentional efforts to balance the customers' interests and the interests of the QF development community in both establishing and implementing the SISC as exemplified by several policy and modeling decisions the Companies made to the benefit of the QF.

First, the Companies made the policy decision to only apply the SISC on a prospective basis—despite both existing and new solar QFs causing the increased integration costs—to smoothly transition the allocation of integration costs to the appropriate cost causer. Alternatively, the Companies could have proposed to retroactively apply the charge to all solar QFs causing the increased integration costs currently paid for by the Companies' customers.

The Companies also made the policy decision to use the average as opposed to incremental solar integration services charge, as discussed in more detail by Duke Witness Wheeler. Put another way, the incremental cap rate for DEC is \$3.20/MWh, but DEC is recommending only a \$1.10/MWh average charge. For DEP, the incremental cap is \$6.70/MWh, but DEP proposes only a \$2.39/MWh average charge. This decision by the Companies to use the average versus incremental charges results in a 290% lower SISC for QF developers in DEC and a 280% lower SISC for QF developers in DEP. This is a significant reduction in the SISC that intervenors have ignored.

Third, the Companies have yet to include what I call the "re-dispatch costs" in its avoided energy rates and the Ancillary Services Study, which are costs that were specifically included in Dominion Energy North Carolina's avoided costs in North Carolina[59] and I believe are included in the way Dominion Energy South Carolina calculates its avoided cost rates. This cost is also not captured by the Companies' avoided energy costs, which are based on adding a 100 MW baseload

[59] Dominion Energy North Carolina Initial Statement, at 12-13, NCUC Docket No. E-100, Sub 158 (Nov. 1, 2018).

resource in every hour, which ignores the ramping of the solar resource within the avoided energy cost calculations. The ramping of 100 MW of solar even on an hourly basis changes the commitment and dispatch of the generators in actual operations and increases starts and ramps for the conventional fleet which, in turn, overstates the avoided energy costs being paid to QF facilities. On the other hand, the Ancillary Services Study is only calculating the costs of ancillary service increases between two cases that have the same amount of solar. If the avoided energy costs included this re-dispatch cost, then there would be a significant deduct to avoided energy rates due to the intermittent nature and ramping of solar that has not been addressed in the Ancillary Services Study.

Fourth, the SERVM model utilized in the Ancillary Services Study and discussed by Duke Witness Wintermantel provides additional benefit to QF resources by allowing the model to perfectly curtail QF resources on an intra-hour basis, which is not something that the Companies can actually do with current QFs in real time operations. To explain, the SERVM model allows for exact curtailment intra hour when required to serve regulation down requirements; however, in actual operations, this capability would have to be served by the conventional fleet which would add additional regulation down costs to the SISC charge. This is because under PURPA, any power injected by a solar QF onto the Companies' systems is "must take," meaning the Companies have limited ability to curtail or dispatch the solar QF outside of emergency situations.

Last, and importantly, the Companies have taken feedback from the QF community to provide two SISC mitigation measures to the benefit of the QF developer. First, terms and conditions addressing the implementation of the SISC charge, provide solar QFs utilizing energy storage the potential to avoid or mitigate the SISC where such solar QFs commit to operating as a "controlled solar generator" and deliver energy in a manner that substantially reduces the intra hour intermittency associated with uncontrolled solar generation. Second, the SISC charge, while adjusted on a biennial basis, is subject to a cap providing developers with a limit on their exposure to the charge. Therefore, intervenors arguments suggesting that the SISC is being unfairly imposed on solar QFs should be dismissed, as the Companies have intentionally balanced both QF's and customer's interests in implementing the SISC.

Q. DOES THE ORS AGREE THAT THE COMPANIES FAIRLY BALANCED BOTH THE QFS' AND THE CUSTOMERS' INTERESTS IN ESTABLISHING THE SISC?

A. Yes. Noting that a fair and balanced integration services charge establishes a rate that benefits the Companies' customers by limiting the risk of subsidization, yet expands private investment in solar development, ORS Witness Lawyer testified that the "proposed integration services charges are designed to assign costs to the QFs who cause the Companies to incur costs to integrate solar generation."[60] He further stated that "the rate design minimizes the risk to the Companies' customers by directly assigning integration costs to the QFs." Additionally, as I stated above, ORS Witness Horii supported the SISC and recommended it be approved by the Commission.

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[60] ORS Lawyer Direct, at 5-6.

b. <u>Response to ORS Witness Horii's Recommendations</u>

Q. PLEASE RESPOND TO ORS WITNESS HORII'S RECOMMENDATION THAT A FORMAL STAKEHOLDER PROCESS AND STAKEHOLDER REPORT TO THE COMMISSION BE REQUIRED FOR FUTURE INTEGRATION SERVICES CHARGE STUDIES.

A. As an initial matter, and as discussed in my Direct Testimony, the Companies agree that it is appropriate to review and update the SISC in each avoided cost proceeding based on then-current conditions to most accurately quantify and allocate the SISC to current and future solar QFs. Although the Companies are not opposed to holding a technical workshop prior to updating the SISC in future avoided cost proceedings, the Companies note that, as exemplified throughout my Rebuttal Testimony, the solar community has a clear interest in advocating for a lower SISC to the benefit of the QF developer. As such, the Companies believe that a technical workshop facilitated by the ORS and involving independent third-party consultants like Mr. Horii of E3 may better support an accurate review and quantification of an updated SISC. Further, the Companies believe that a formal report submitted to the Commission would create an unnecessary administrative burden on both the Companies and the Commission, especially as the Companies plan to file the updated study with the Commission in each future avoided cost proceeding. Interested parties will then have the right to review the updated study and any disagreement can be resolved by the Commission.

c. **Response to SBA Witness Burgess**

Q. HOW DO YOU RESPOND TO SBA WITNESS BURGESS' ARGUMENT THAT IMPLEMENTATION OF THE SISC IS PREMATURE AND THAT AN INDEPENDENT ANALYSIS IS REQUIRED PURSUANT TO ACT 62 PRIOR TO IMPLEMENTATION OF THE SISC?

A. I believe Mr. Burgess is mistaken is his interpretation of the language in Act 62. I am very familiar with Act 62, as I was an active participant providing stakeholder input on Duke's behalf during its development. In particular, Act 62 authorizes the Commission and the ORS to initiate an integration study and states,

> "An integration study conducted pursuant to this section shall evaluate what is required for electrical utilities to integrate increased levels of renewable energy and emerging energy technologies while maintaining economic, reliable, and safe operation of the electricity grid in a manner consistent with the public interest."

The clear intent of the study referred in Act 62 was to identify what additional actions and investments would be required to accommodate higher levels of intermittent generation on the grid. Such a study would identify future potential grid assets that help to enable increasing levels of intermittent generation in a safe and reliable manner. However, unlike the Companies' integration cost study supporting the SISC, nothing contemplated in this language would suggest the Act 62 study's objective is to quantify the specific costs borne by consumers associated with the provision of additional operational reserves also known as ancillary services. Furthermore, as solar penetration increases and additional actions are taken to integrate those resources in a safe and reliable manner, such changes will be taken into account in future SISC studies and charges will be updated accordingly. Mr. Burgess is simply asking the Commission to continue to allow the current subsidization occurring from consumers to QF developers to continue without basis. As such, his recommendation should be rejected.

Q. HOW DO YOU RESPOND TO SBA WITNESS BURGESS' ARGUMENT THAT DUKE FAILED TO ADDRESS THE FACT THAT SOLAR CAN PROVIDE ANCILLARY SERVICES AND REDUCED COSTS IN ESTABLISHING THE SISC?

A. I disagree with SBA Witness Burgess. First and foremost, although the integration of energy storage systems can potentially mitigate the increased ancillary services costs caused by solar QF's uncontrolled operations, any cost benefit to the grid provided by the QF is limited to eliminating the intermittency and volatility caused by the solar QFs in the first place. Providing additional ancillary service benefit beyond mitigating that caused by the intermittent resource itself is not envisioned by PURPA, nor would it be economic under a must take PURPA contract for solar QFs to provide additional ancillary services to the utility. As I explained above, the energy provided by solar QFs under PURPA is a "must take" obligation, meaning the solar QFs are non-dispatchable and that the utility cannot curtail the solar QF unless and until there is a system emergency. By definition, the provision of additional ancillary services requires that the utility have full control and dispatch the resource in real-time with the ability to regularly pre-curtail, further curtail, and then dispatch the resource on a minute-to-minute basis. This would significantly reduce the output of the QF relative to its must-take rights under PURPA contracts. This type of operation does conform with must take PURPA

QFs' operations. Duke Witness Holeman arrives at a similar conclusion from a system operator's perspective.

Additionally, as explained previously and in my Direct Testimony, the Companies are proposing to allow solar generators who are not "must take" QFs and who contractually agree to operate their facilities through use of energy storage devices, dispatchable contracts, or other mechanisms that reduce or eliminate the intermittency of the facilities' generation output can eliminate the Companies' additional ancillary services costs and therefore appropriately avoid the Integration Services Charge designed to recover these costs.

d. <u>Response to SACE/CCL Witness Kirby</u>

Q. HOW DO YOU RESPOND TO SACE/CCL WITNESS KIRBY'S ASSERTION THAT DUKE "FAILED" TO ADHERE TO THE NORTH CAROLINA UTILITIES COMMISSION'S REQUEST FOR DUKE TO PROVIDE ITS ACTUAL HISTORICAL OPERATING RESERVES?

A. I disagree. The NCUC made a request at the conclusion of the hearing, July 19, 2019, for detailed historic operating reserves. The Companies promptly responded to the NCUC's request with the level of detail and history available to Duke the NCUC accepted the Companies' response. Furthermore, the NCUC did not request additional information on the matter nor did they contend that the Companies were non-responsive in their submittal. Mr. Kirby has not accurately represented the facts in this situation.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.